



Indiana Department of Environmental Management

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Michael R. Pence
Governor

Carol S. Comer
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NOTICE OF 30-DAY PERIOD FOR PUBLIC COMMENT

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

for Duke Energy Indiana, Inc. - Gibson Generating Station in Gibson County

Significant Permit Modification No.: 051-36994-00013

The Indiana Department of Environmental Management (IDEM) has received an application from Duke Energy Indiana, Inc. - Gibson Generating Station (GGS), located at 1097 N 950 West, Owensville, Indiana 47665, for a significant modification of its Part 70 Operating Permit issued on January 16, 2014. If approved by IDEM's Office of Air Quality (OAQ), this proposed modification would allow Duke Energy Indiana, Inc. - GGS to make certain changes at its existing source. Duke Energy Indiana, Inc. - GGS has applied to remove "(whichever is later)" everywhere it is used in regards to the Unit 5 PM CEMS thereby making the PM CEMS the current compliance method for PM and opacity. The Permit also includes NESHAP 40 CFR 63 Subpart UUUUU and the requirements of the Cross-State Air Pollution Rule (CSAPR). This draft Part 70 Operating 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:

Owensville Carnegie Public Library
110 S. Main Street
Owensville IN 47665

and

IDEM Southwest Regional Office
1120 N. Vincennes Avenue
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/>.

How can you participate in this process?

The date that this notice is published in a newspaper marks the beginning of a 30-day public comment period. If the 30th day of the comment period falls on a day when IDEM offices are closed for business, all comments must be postmarked or delivered in person on the next business day that IDEM is open.

You may request that IDEM hold a public hearing about this draft permit. If adverse comments concerning the **air pollution impact** of this draft permit are received, with a request for a public hearing,

IDEM will decide whether or not to hold a public hearing. IDEM could also decide to hold a public meeting instead of, or in addition to, a public hearing. If a public hearing or meeting is held, IDEM will make a separate announcement of the date, time, and location of that hearing or meeting. At a hearing, you would have an opportunity to submit written comments and make verbal comments. At a meeting, you would have an opportunity to submit written comments, ask questions, and discuss any air pollution concerns with IDEM staff.

Comments and supporting documentation, or a request for a public hearing should be sent in writing to IDEM at the address below. If you comment via e-mail, please include your full U.S. mailing address so that you can be added to IDEM's mailing list to receive notice of future action related to this permit. If you do not want to comment at this time, but would like to receive notice of future action related to this permit application, please contact IDEM at the address below. Please refer to permit number SPM 051-36994-00013 in all correspondence.

Comments should be sent to:

Vasantha Palakurti
IDEM, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
(800) 451-6027, ask for extension 4-9694
Or dial directly: (317) 234-9694
Fax: (317) 232-6749 attn: Vasantha palakurti
E-mail: Vpalakur@idem.IN.gov

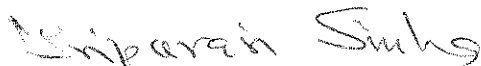
All comments will be considered by IDEM when we make a decision to issue or deny the permit. Comments that are most likely to affect final permit decisions are those based on the rules and laws governing this permitting process (326 IAC 2), air quality issues, and technical issues. IDEM does not have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

For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Permit Guide on the Internet at: <http://www.in.gov/idem/5881.htm>; and the Citizens' Guide to IDEM on the Internet at: <http://www.in.gov/idem/6900.htm>.

What will happen after IDEM makes a decision?

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


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



Indiana Department of Environmental Management

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Michael R. Pence
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Carol S. Comer
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Ms. Sheryl Fisher
Duke Energy Indiana - Gibson Station
1000 East Main Street
Plainfield, IN 46168

Re: 051-36994-00013
Significant Permit Modification to
Part 70 Renewal No.: T051-33624-00013

Dear Ms. Fisher:

Duke Energy Indiana, Inc. - Gibson Generating Station was issued a Part 70 Operating Permit Renewal No. 051-33624-00013 on January 16, 2014 for a stationary electric utility generating station located at 1097 North 950 West, Owensville, Indiana. An application requesting changes to this permit was received on March 23, 2016. Pursuant to the provisions of 326 IAC 2-7-12, a significant permit modification to this permit is hereby approved as described in the attached Technical Support Document.

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

Attachment F: NESHAP 40 CFR 63, Subpart UUUUU

The permit references the below listed attachments since these attachments were provided in previously issued approvals for this source, IDEM OAQ has not included a copy of these attachments with this modification:

Attachment A: NSPS 40 CFR 60, Subpart D
Attachment B: NSPS 40 CFR 60, Subpart OOO
Attachment C: CAM Plan
Attachment D: NSPS 40 CFR 60, Subpart IIII
Attachment E: NESHAP 40 CFR 63, Subpart ZZZZ

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

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

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

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

If you have any questions on this matter, please contact Vasantha Palakurti, of my staff, at 317-234-9694 or 1-800-451-6027, and ask for extension 4-9694.

Sincerely,

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

Attachment(s): Updated Permit and Technical Support Document

TS/PV

cc: File - Gibson County
Gibson County Health Department
U.S. EPA, Region V
Compliance and Enforcement Branch
Southwest Regional Office



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Part 70 Operating Permit Renewal OFFICE OF AIR QUALITY

Duke Energy Indiana, LLC - Gibson Generating Station 1097 N 950 W Owensville, Indiana 47665

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

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

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

Operation Permit No.: T051-33624-00013	
Issued by: Tripurari P. Sinha, Ph. D., Section Chief Permits Branch Office of Air Quality	Issuance Date: January 16, 2014 Expiration Date: January 16, 2019

Significant Permit Modification No.: 051-34614-00013, issued October 7, 2014
Administrative Amendment No.: 051--36763-00013, issued February 11, 2016

Significant Permit Modification No: 051-36994-00013	
Issued by: Tripurari P. Sinha, Ph. D., Section Chief Permits Branch Office of Air Quality	Issuance Date: Expiration Date: January 16, 2019



TABLE OF CONTENTS

SECTION A SOURCE SUMMARY 10

- A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(22)]
- A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)]
[326 IAC 2-7-5(14)]
- A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)]
[326 IAC 2-7-5(14)]
- A.4 Part 70 Permit Applicability [326 IAC 2-7-2]

SECTION B GENERAL CONDITIONS..... 15

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

SECTION C SOURCE OPERATION CONDITIONS..... 26

Emission Limitations and Standards [326 IAC 2-7-5(1)] 26

- C.1 Particulate Emission Limitations For Processes with Process Weight Rates Less
Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]
- C.2 Opacity [326 IAC 5-1]
- C.3 Open Burning [326 IAC 4-1] [IC 13-17-9]
- C.4 Incineration [326 IAC 4-2] [326 IAC 9-1-2]
- C.5 Fugitive Dust Emissions [326 IAC 6-4]
- C.6 Stack Height [326 IAC 1-7]
- C.7 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]
- C.8 Performance Testing [326 IAC 3-6]
- C.9 Compliance Requirements [326 IAC 2-1.1-11]
- C.10 Compliance Monitoring
[326 IAC 2-7-5(3)][326 IAC 2-7-6(1)][40 CFR 64][326 IAC 3-8]
- C.11 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] 29

C.12 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]
Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

C.13 Risk Management Plan [326 IAC 2-7-5(12)] [40 CFR 68]

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

C.15 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] 32

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

C.17 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]
[326 IAC 2-2][326 IAC 2-3]

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

Stratospheric Ozone Protection 36

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

Ambient Monitoring Requirements [326 IAC 7-3] 36

C.20 Ambient Monitoring [326 IAC 7-3]

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS 37

Emission Limitations and Standards [326 IAC 2-7-5(1)] 37

D.1.1 PSD BACT Requirements [326 IAC 2-2-3]

D.1.2 Sulfur Dioxide (SO₂) and Pollution Control Project [326 IAC 7-4-12.1][326 IAC 2-2.3]
[326 IAC 2-3.3]

D.1.3 Reserved

D.1.4 Preventive Maintenance Plan [326 IAC 1-6-3]

Compliance Determination Requirements [326 IAC 2-7-5(1)]..... 37

D.1.5 Reserved

D.1.6 Operation of Electrostatic Precipitator and Flue gas Desulfurization [326 IAC 2-7-6(6)]

D.1.7 Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

D.1.8 Sulfur Dioxide Emissions [326 IAC 7-2][326 IAC 7-4-12.1][326 IAC 2-7-5(3)(A)][326 IAC 2-7-6]

D.1.9 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]..... 39

D.1.10 SO₂ Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

D.1.11 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 40

D.1.12 Record Keeping Requirement

D.1.13 Reporting Requirement

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS 42

Emission Limitations and Standards [326 IAC 2-7-5(1)] 42

D.2.1 PSD BACT Requirements [326 IAC 2-2-3]

D.2.2 Sulfur Dioxide (SO₂) and Pollution Control Project [326 IAC 7-4-12.1][326 IAC 2-2.3]
[326 IAC 2-3.3]

- D.2.3 Reserved
- D.2.4 Preventive Maintenance Plan [326 IAC 1-6-3]
- Compliance Determination Requirements [326 IAC 2-7-5(1)]..... 42**
- D.2.5 Reserved
- D.2.6 Operation of Electrostatic Precipitator and Flue Desulfurization (FGD)
[326 IAC 2-7-6(6)]
- D.2.7 Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]
- D.2.8 Sulfur Dioxide Emissions [326 IAC 7-2][326 IAC 7-4-12.1][326 IAC 2-7-5(3)(A)][326 IAC 2-7-6]
- D.2.9 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]
- Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]..... 44**
- D.2.10 SO₂ Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]
- D.2.11 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]
- Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 45**
- D.2.12 Record Keeping Requirement
- D.2.13 Reporting Requirement
- SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS 47**
- Emission Limitations and Standards [326 IAC 2-7-5(1)] 47**
- D.3.1 PSD BACT Requirements [326 IAC 2-2-3]
- D.3.2 Sulfur Dioxide (SO₂) and Pollution Control Project [326 IAC 7-4-12.1][326 IAC 2-2-3] [326 IAC 2-3.3]
- D.3.3 Reserved
- D.3.4 Preventive Maintenance Plan [326 IAC 1-6-3]
- Compliance Determination Requirements [326 IAC 2-7-5(1)]..... 47**
- D.3.5 Reserved
- D.3.6 Operation of Electrostatic Precipitator and Flue Gas Desulfurization (FGD)
[326 IAC 2-7-6(6)]..... 48**
- D.3.7 Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]
- D.3.8 Sulfur Dioxide Emissions [326 IAC 7-2][326 IAC 7-4-12.1][326 IAC 2-7-5(3)(A)][326 IAC 2-7-6]
- D.3.9 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]
- D.3.10 SO₂ Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]
- D.3.11 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]
- Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 50**
- D.3.12 Record Keeping Requirements
- D.3.12 Reporting Requirement
- Emission Limitations and Standards [326 IAC 2-7-5(1)] 52**
- D.4.1 PSD BACT Requirements [326 IAC 2-2-3]
- D.4.2 Sulfur Dioxide (SO₂) Limitations [326 IAC 7-4-12.1]
- D.4.3 Reserved
- D.4.4 Preventive Maintenance Plan [326 IAC 1-6-3]

Compliance Determination Requirements [326 IAC 2-7-5(1)]..... 52

- D.4.5 Reserved
- D.4.6 Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]
- D.4.7 Flue Gas Desulfurization (FGD) System [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]
- D.4.8 Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]
- D.4.9 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]
- D.4.10 Sulfur Dioxide Emissions [326 IAC 2-7-5(3)(A)][326 IAC 2-7-6][326 IAC 3-5]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]..... 54

- D.4.11 SO₂ Monitor System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(1)]
- D.4.12 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 54

- D.4.13 Record Keeping Requirements
- D.4.14 Reporting Requirements

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS 57

Emission Limitations and Standards [326 IAC 2-7-5(1)] 57

- D.5.1 PSD BACT Requirements [326 IAC 2-2-3]
- D.5.2 Sulfur Dioxide (SO₂) Limitations [326 IAC 7-4-12.1]
- D.5.3 Reserved
- D.5.4 Preventive Maintenance Plan [326 IAC 1-6-3]

Compliance Determination Requirements [326 IAC 2-7-5(1)]..... 57

- D.5.5 Reserved
- D.5.6 Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]
- D.5.7 Flue Gas Desulfurization (FGD) System [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]
- D.5.8 Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]
- D.5.9 Sulfur Dioxide Emissions [326 IAC 2-7-5(3)(A)][326 IAC 2-7-6][326 IAC 3-5]
- D.5.10 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]..... 59

- D.5.11 SO₂ Monitor System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(1)]
- D.5.12 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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

- D.5.13 Record Keeping Requirements
- D.5.14 Reporting Requirements
- D.5.15 ORDER of the Commissioner of the Indiana Department of Environmental Management

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS 62

Emission Limitations and Standards [326 IAC 2-7-5(1)] 62

- 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(13)]

Compliance Determination Requirements [326 IAC 2-7-5(1)]..... 63

- D.6.3 Particulate Control [326 IAC 2-7-6(6)]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]..... 63

- D.6.4 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 63
D.6.5 Record Keeping Requirements

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS 65

Emission Limitations and Standards [326 IAC 2-7-5(1)] 65
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(13)]

Compliance Determination Requirements [326 IAC 2-7-5(1)]..... 66
D.7.2 Particulate Control [326 IAC 2-7-6(6)]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]..... 66
D.7.3 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 67
D.7.4 Record Keeping Requirement

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS 68

Emission Limitations and Standards [326 IAC 2-7-5(1)] 68
D.8.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]
D.8.2 Preventive Maintenance Plan (PMP) [326 IAC 2-7-5(13)]

Compliance Determination Requirements [326 IAC 2-7-5(1)]..... 69
D.8.3 Particulate Control [326 IAC 2-7-6(6)]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]..... 69
D.8.4 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 70
D.8.5 Record Keeping Requirement

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS 71

Emission Limitations and Standards [326 IAC 2-7-5(1)] 71
D.9.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]
D.9.2 Preventive Maintenance Plan (PMP) [326 IAC 2-7-5(13)]
D.9.3 Particulate Control [326 IAC 2-7-6(6)]

Compliance Monitoring Requirements [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]..... 72
D.9.4 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-19] 72
D.9.5 Record Keeping Requirements

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS 73

Emission Limitations and Standards [326 IAC 2-7-5(1)] 73
D.10.1 PSD Minor Limits and Particulate Emission Limitation for Manufacturing Processes
[326 IAC 2-2] [326 IAC 6-3-2]
D.10.2 Emission Offset [326 IAC 2-3]
D.10.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

Compliance Determination Requirements [326 IAC 2-7-5(1)]..... 75
D.10.4 Particulate Control [326 IAC 2-7-6(6)]
D.10.5 Testing requirements [326 IAC 2-7-6(1),(6)][326 IAC 2-1.1-11]

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]..... 76
D.10.6 Visible Emissions Notations [40 CFR 64]
D.10.7 Reserved

Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 77
D.10.8 Record Keeping Requirements [40 CFR 64]
D.10.9 Reporting Requirements

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS 79

Emission Limitations and Standards [326 IAC 2-7-5(1)] 79

 D.11.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

 D.11.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

SECTION E.1 ACID RAIN PROGRAM CONDITIONS 80

ORIS Code: 6113 80

Emission Limitations and Standards [326 IAC 2-7-5(1)] 81

 E.1.1. Statutory and Regulatory Authorities

 E.1.2. Standard Permit Requirements [326 IAC 21]

 E.1.3. Monitoring Requirements [326 IAC 21]

 E.1.4. Sulfur Dioxide Requirements [326 IAC 21]

 E.1.5. Nitrogen Oxides Requirements [326 IAC 21]

 E.1.6. Excess Emissions Requirements [40 CFR 77] [326 IAC 21]

 E.1.7. Record Keeping and Reporting Requirements [326 IAC 21]

 E.1.8. Submissions [326 IAC 21]

 E.1.9. Severability [326 IAC 21]

 E.1.10. Liability [326 IAC 21]

 E.1.11. Effect on Other Authorities [326 IAC 21]

SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS 88

New Source Performance Standards [326 IAC 12] [40 CFR Part 60, Subpart D]..... 88

 E.2.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1]
 [40 CFR Part 60, Subpart A]

 E.2.2 New Source Performance Standards of Performance for Fossil-Fuel-Fired Steam
 Generators [40 CFR Part 60, Subpart D] [326 IAC 12]

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS 89

New Source Performance Standards [326 IAC 12] [40 CFR Part 60, Subpart OOO]..... 90

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

 E.3.2 New Source Performance Standards for Standard of Performance for Non-metallic
 Mineral Processing Plants [40 CFR Part 60, Subpart OOO] [326 IAC 12]

SECTION E.4 EMISSIONS UNIT OPERATION CONDITIONS 91

New Source Performance Standards [326 IAC 12] [40 CFR 60, Subpart IIII] 91

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

 E.4.2 Standards of Performance for Stationary Compression Ignition Internal Combustion
 Engines [326 IAC 12][40 CFR Part 60, Subpart IIII]

SECTION E.5 EMISSIONS UNIT OPERATION CONDITIONS 92

**National Emissions Standard for Hazardous Air Pollutants [326 IAC 20] [40 CFR 63,
 Subpart ZZZZ]..... 92**

 E.5.1 General Provisions Relating to National Emissions Standard for Hazardous Air
 Pollutants for Stationary Reciprocating Internal Combustion Engines [326 IAC 20-
 1][40 CFR Part 63, Subpart A]

 E.5.2 National Emissions Standard for Hazardous Air Pollutants for stationary
 Reciprocating Internal Combustion Engines [40 CFR Part 63, Subpart ZZZZ][326
 IAC 20-82-1]

SECTION E.6 EMISSIONS UNIT OPERATION CONDITIONS 93

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]..... 94

E.6.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

E.6.2 Coal- And Oil-Fired Electric Utility Steam Generating Units NESHAP [40 CFR Part 63, Subpart UUUUU][326 IAC 20-89]

SECTION F.1 SO₃ MITIGATION PLAN..... 96

F.1 SO₃ Mitigation System [326 IAC 2-2.3]

F.2 Reserved

F.3 Minimum Injection Rate

F.4 Plume Touchdown

SECTION G 98

TR NO_x Annual Trading Program, TR NO_x Ozone Season Trading Program, and TR SO₂ Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.506), (40 CFR 97.606) 98

G.1 Designated representative requirements

G.2 Emissions monitoring, reporting, and recordkeeping requirements

G.3 NO_x annual emissions requirements

G.4 NO_x ozone season requirements

G.5 SO₂ emissions requirements

G.6 Title V Permit Revision Requirements

G.7 Additional recordkeeping and reporting requirements

G.8 Liability

G.9 Effect on other authorities

SECTION H Clean Air Interstate Rule (CAIR) Nitrogen Oxides Annual, Sulfur Dioxide, and Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a) 109

Emission Limitations and Standards [326 IAC 2-7-5(1)] 110

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

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

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

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

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

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

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

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

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

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

- H.9 Effect on Other Authorities [326 IAC 24-1-4(g)] [326 IAC 24-2-4(g)]
[326 IAC 24-3-4(g)] [40 CFR 97.106(g)] [40 CFR 97.206(g)] [40 CFR 97.306(g)]
- H.10 CAIR Designated Representative and Alternate CAIR Designated Representative
[326 IAC 24-1-6] [326 IAC 24-2-6] [326 IAC 24-3-6] [40 CFR 97, Subpart BB]
[40 CFR 97, Subpart BBB] [40 CFR 97, Subpart BBBB]

- Attachment A: NSPS 40 CFR 60, Subpart D
- Attachment B: NSPS 40 CFR 60, Subpart OOO
- Attachment C: CAM Plan
- Attachment D: NSPS 40 CFR 60, Subpart IIII
- Attachment E: NESHAP 40 CFR 63, Subpart ZZZZ
- Attachment F: NESHAP 40 CFR 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.3 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

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

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

Source Address:	1097 N 950 W, Owensville, Indiana 47665
General Source Phone Number:	317-838-2108
SIC Code:	4911
County Location:	Gibson
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 No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr) and an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack D.

Boiler No. 4 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x) sulfur dioxide (SO₂) and particulate matter (PM)

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack C.

Boiler No. 5 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (f) A coal transfer system, with a nominal throughput of 6,000 tons of coal per hour, consisting of the following equipment:
- (1) Two (2) railcar unloading stations, each with a drop point to a hopper identified as DP-5 and DP-25, with the drop point controlled by a partial enclosure, and exhausting to the ambient air.
 - (2) Two (2) active piles, each with a drop point to a hopper identified as DP-1 and DP-16, with each drop point enclosed and exhausting to the ambient air.
 - (3) Three (3) storage piles, having an estimated combined storage capacity including the active piles of 4,000,000 tons, with fugitive emissions controlled by watering trucks.
 - (4) Four (4) enclosed hoppers, each with a drop point to conveyors identified as DP-2, DP-6, DP-17 and DP-26, with each drop point enclosed and exhausting to the ambient air.
 - (5) An enclosed conveyor system, with 18 drop points identified as DP-3, DP-4, DP-7 through DP-15, and DP-14 through DP-22, with each drop point enclosed, excluding the two (2) active pile conveyors which have the drop points (DP-18 and DP-22) controlled by either telescopic chutes or a dust suppression system, and exhausting to the ambient air.
 - (6) Five (5) enclosed coal bunkers, each with a nominal capacity of 15,000 tons of coal. Bunkers are loaded via a conveyor tripper system with a total capacity of 3,000 tons per hour to the units 1 and 2 bunkers, and 3,000 tons per hour to the units 3, 4 and 5 bunkers.

- (g) A limestone processing system, consisting of the following equipment:
- (1) One (1) unloading station for trucks or railcar, with a drop point to a hopper identified as LSDP-1 with a nominal throughput of 2,500 tons of limestone per hour, with the drop point controlled by a partial enclosure, and exhausting to the ambient air.
 - (2) Two (2) enclosed hoppers, each with a drop point to conveyors identified as LSDP-2 and LSDP-5 with a nominal throughput of 200 tons of limestone per hour, with each drop point enclosed.
 - (3) One (1) storage pile, with a nominal storage capacity of 50,000 tons, with a drop point to a hopper identified as LSDP-4, with the drop point enclosed and exhausting to the ambient air.
 - (4) An enclosed conveyor system, with four (4) drop points identified as LSDP-3 and LSDP-8 through LSDP-10, with each drop point enclosed.
 - (5) One (1) enclosed ball mill, with a drop point to a conveyor identified as LSDP-6, with the drop point enclosed.
 - (6) Two (2) day bins for temporary storage of limestone, with a combined storage capacity of 13,000 tons, with dust from loading the bins controlled by bin vent filters, and exhausting to the ambient air.
- (h) Limestone Handling (TP-1 to TP-5, TP-10 to TP-17, F-6 and F-9), with maximum capacity of 2,500 tons per hour:
- (1) Transfer of limestone from railcar or truck to the limestone hopper, with fogging type dust suppression as particulate control.
 - (2) Enclosed transfer of limestone from unloading hoppers to belt feeders.
 - (3) Enclosed transfer of limestone from belt feeders to conveyors.
 - (4) Telescoping chute transfer of limestone from conveyor to lime storage stockout pile.
 - (5) Enclosed transfer of limestone from the reclaim hoppers to belt feeders, with fogging type dust suppression as particulate control.
 - (6) Enclosed transfer of limestone from conveyor to conveyor, with fogging type dust suppression as particulate control.
 - (7) Transfer of limestone from conveyor to day bin, with surge-bin filter as particulate control.
 - (8) Enclosed transfer of limestone from conveyor fixed hopper to conveyor with fogging type dust suppression as particulate control.
 - (9) Transfer of limestone from conveyor fixed tripper to day bin, with surge-bin filter as particulate control.
 - (10) Limestone storage piles, with watering type dust suppression as fugitive dust control.

- (i) Gypsum Handling (TP-26 to TP-35, TP-38, and TP-39), with maximum capacity of 300 tons per hour:
 - (1) Enclosed transfer of gypsum from belt feeders to conveyors.
 - (2) Transfer of gypsum from conveyors to stockout piles.
 - (3) Partially enclosed transfer of gypsum from conveyor to radial stacker conveyor.
 - (4) Transfer of gypsum from radial stacker conveyor to stockout pile.
 - (5) Stockout piles.
- (j) Dry fly ash handling system, including the following, permitted in 2011:
 - (1) one (1) pneumatic fly ash transfer system from existing precipitator hoppers for Units 1, 2, and 3 equipped with separators/exhausters designated as 1A, 1B, 2A, 2B, 2C, 3A, 3B and 3C to two (2) new transfer stations designated as B1 & B2 each with a maximum capacity of 200 tons per hour. The particulate emissions from each transfer station silo will be controlled by bin-vent filters to 0.01 gr/dscf.
 - (2) one (1) pneumatic fly ash transfer system conveying ash from the two (2) transfer station silos to two (2) new fixation silos designated as B3 & B4 each with a maximum capacity of 200 tons per hour. The particulate emissions from each fixation silo will be controlled by bin-vent filters to 0.01 gr/dscf.
 - (3) one (1) pneumatic fly ash transfer system equipped enclosed screw conveyers from the two (2) fixation silos to a new Fixation Building with particulate emissions controlled by a dust collector C1 (with a spare dust collector C2).
 - (4) Loading of fly ash into trucks for transport to the landfill from fixation silos B3 & B4 using wet unloaders.
 - (5) Truck loading of two (2) new lime silos designated B5 & B6 for use in the Fixation Building, each with bin-vent filters controlling particulate matter emissions to 0.01 gr/dscf.
 - (6) One (1) fly ash day bin designated B7 with a maximum capacity of 200 tons per hour with particulate matter emissions controlled by a bin-vent filter to 0.01 gr/dscf.

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)]
 [326 IAC 2-7-5(14)]

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

- (a) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring; buffing; polishing; abrasive blasting; pneumatic conveying; and woodworking operations.[326 IAC 6-3-2]
- (b) Conveyors as follows: [326 IAC 6-3]
 - (1) Covered conveyor for coal or coke conveying of less than or equal to 360 tons

- per day;
- (2) Covered conveyors for limestone conveying of less than or equal to 7,200 tons per day for sources other than mineral processing plants constructed after August 31, 1983;
 - (3) Underground conveyors.
- (c) Coal bunker and coal scale exhausts and associated dust collector vents. [326 IAC 6-3]
 - (d) One (1) emergency firewater pump engine, rated at 500 horsepower (HP) and identified as Pump #1, installed in 1995 and permitted in 2013.
[Under 40 CFR 63, Subpart ZZZZ, the firewater pump engine is considered an existing affected source.]
 - (e) One (1) emergency firewater pump engine, rated at 575 horsepower (HP) and identified as Pump #2, installed in 2007 and permitted in 2013.
[Under 40 CFR 60, Subpart IIII, the firewater pump engine is considered an existing affected source.]

A.4 Part 70 Permit Applicability [326 IAC 2-7-2]

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

- (a) It is a major source, as defined in 326 IAC 2-7-1(22);
- (b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).
- (c) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3);

SECTION B GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-7-1]

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

B.2 Permit Term [326 IAC 2-7-5(2)][326 IAC 2-1.1-9.5][326 IAC 2-7-4(a)(1)(D)][IC 13-15-3-6(a)]

- (a) This permit, T051-33624-00013, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).
- (b) If IDEM, OAQ, upon receiving a timely and complete renewal permit application, fails to issue or deny the permit renewal prior to the expiration date of this permit, this existing permit shall not expire and all terms and conditions shall continue in effect, including any permit shield provided in 326 IAC 2-7-15, until the renewal permit has been issued or denied.

B.3 Term of Conditions [326 IAC 2-1.1-9.5]

Notwithstanding the permit term of a permit to construct, a permit to operate, or a permit modification, any condition established in a permit issued pursuant to a permitting program approved in the state implementation plan shall remain in effect until:

- (a) the condition is modified in a subsequent permit action pursuant to Title I of the Clean Air Act; or
- (b) the emission unit to which the condition pertains permanently ceases operation.

B.4 Enforceability [326 IAC 2-7-7] [IC 13-17-12]

Unless otherwise stated, all terms and conditions in this permit, including any provisions designed to limit the source's potential to emit, are enforceable by IDEM, the United States Environmental Protection Agency (U.S. EPA) and by citizens in accordance with the Clean Air Act.

B.5 Severability [326 IAC 2-7-5(5)]

The provisions of this permit are severable; a determination that any portion of this permit is invalid shall not affect the validity of the remainder of the permit.

B.6 Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]

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

B.7 Duty to Provide Information [326 IAC 2-7-5(6)(E)]

- (a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. Upon request, the Permittee shall also furnish to IDEM, OAQ copies of records required to be kept by this permit.
- (b) For information furnished by the Permittee to IDEM, OAQ, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1. When furnishing copies of requested records directly to U. S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.

B.8 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]

- (a) A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:
- (1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(35), and
 - (2) the certification states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
- (b) The Permittee may use the attached Certification Form, or its equivalent with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.
- (c) A "responsible official" is defined at 326 IAC 2-7-1(35).

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

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

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

and

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

- (b) The annual compliance certification report required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.
- (c) The annual compliance certification report shall include the following:
- (1) The appropriate identification of each term or condition of this permit that is the basis of the certification;
 - (2) The compliance status;
 - (3) Whether compliance was continuous or intermittent;
 - (4) The methods used for determining the compliance status of the source, currently and over the reporting period consistent with 326 IAC 2-7-5(3); and

- (5) Such other facts, as specified in Sections D of this permit, as IDEM, OAQ may require to determine the compliance status of the source.

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

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

- (a) A Preventive Maintenance Plan (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 T051-33624-00013 and issued pursuant to permitting programs approved into the state implementation plan have been either:
 - (1) incorporated as originally stated,
 - (2) revised under 326 IAC 2-7-10.5, or
 - (3) deleted under 326 IAC 2-7-10.5.
- (b) Provided that all terms and conditions are accurately reflected in this permit, all previous registrations and permits are superseded by this Part 70 operating permit, except for permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control)

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

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

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

- (a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).
- (b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ determines any of the following:
- (1) That this permit contains a material mistake.
 - (2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.
 - (3) That this permit must be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-7-9(a)(3)]
- (c) Proceedings by IDEM, OAQ to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-7-9(b)]
- (d) The reopening and revision of this permit, under 326 IAC 2-7-9(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ may provide a shorter time period in the case of an emergency. [326 IAC 2-7-9(c)]

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

- (a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Request for renewal shall be submitted to:

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

- (b) A timely renewal application is one that is:
- (1) Submitted at least nine (9) months prior to the date of the expiration of this permit; and
 - (2) If the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the

document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

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

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

- (a) Permit amendments and modifications are governed by the requirements of 326 IAC 2-7-11 or 326 IAC 2-7-12 whenever the Permittee seeks to amend or modify this permit.
- (b) Pursuant to 326 IAC 2-7-11(b) and 326 IAC 2-7-12(a), administrative Part 70 operating permit amendments and permit modifications for purposes of the acid rain portion of a Part 70 permit shall be governed by regulations promulgated under Title IV of the Clean Air Act. [40 CFR 72]
- (c) Any application requesting an amendment or modification of this permit shall be submitted to:
- Indiana Department of Environmental Management
 Permit Administration and Support Section, Office of Air Quality
 100 North Senate Avenue
 MC 61-53 IGCN 1003
 Indianapolis, Indiana 46204-2251
- Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).
- (d) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

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

- (a) No Part 70 permit revision or notice shall be required under any approved economic incentives, marketable Part 70 permits, emissions trading, and other similar programs or processes for changes that are provided for in a Part 70 permit.
- (b) Notwithstanding 326 IAC 2-7-12(b)(1) and 326 IAC 2-7-12(c)(1), minor Part 70 permit modification procedures may be used for Part 70 modifications involving the use of economic incentives, marketable Part 70 permits, emissions trading, and other similar approaches to the extent that such minor Part 70 permit modification procedures are explicitly provided for in the applicable State Implementation Plan (SIP) or in applicable requirements promulgated or approved by the U.S. EPA.

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

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

- (1) The changes are not modifications under any provision of Title I of the Clean Air Act;
- (2) Any preconstruction approval required by 326 IAC 2-7-10.5 has been obtained;
- (3) The changes do not result in emissions which exceed the limitations provided in this permit (whether expressed herein as a rate of emissions or in terms of total emissions);
- (4) The Permittee notifies the:

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

and

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

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

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

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

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

- (1) A brief description of the change within the source;
- (2) The date on which the change will occur;
- (3) Any change in emissions; and
- (4) Any permit term or condition that is no longer applicable as a result of the change.

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

- (c) Emission Trades [326 IAC 2-7-20(c)]
 The Permittee may trade emissions increases and decreases at the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-7-20(c).
- (d) Alternative Operating Scenarios [326 IAC 2-7-20(d)]
 The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(9). No prior notification of IDEM, OAQ or U.S. EPA is required.
- (e) Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the notification requirements of part (a) of this condition do not apply.
- (f) This condition does not apply to emission trades of SO₂ or NO_x under 326 IAC 21 or 326 IAC 10-4.

B.20 Source Modification Requirement [326 IAC 2-7-10.5]

A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2.

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

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

- (a) Enter upon the Permittee's premises where a Part 70 source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
- (b) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, have access to and copy any records that must be kept under the conditions of this permit;
- (c) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;
- (d) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, sample or monitor substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and
- (e) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

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

- (a) The Permittee must comply with the requirements of 326 IAC 2-7-11 whenever the Permittee seeks to change the ownership or operational control of the source and no other change in the permit is necessary.
- (b) Any application requesting a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new Permittee. The application shall be submitted to:

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

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

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

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

- (a) The Permittee shall pay annual fees to IDEM, OAQ within thirty (30) calendar days of receipt of a billing. Pursuant to 326 IAC 2-7-19(b), if the Permittee does not receive a bill from IDEM, OAQ the applicable fee is due April 1 of each year.
- (b) Except as provided in 326 IAC 2-7-19(e), failure to pay may result in administrative enforcement action or revocation of this permit.
- (c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-4230 (ask for OAQ, Billing, Licensing, and Training Section), to determine the appropriate permit fee.

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

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

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

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

C.2 Opacity [326 IAC 5-1]

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

- (a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.
- (b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

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

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

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

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

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

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

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

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

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

- (a) Notification requirements apply to each owner or operator. If the combined amount of regulated asbestos containing material (RACM) to be stripped, removed or disturbed is at least 260 linear feet on pipes or 160 square feet on other facility components, or at least

thirty-five (35) cubic feet on all facility components, then the notification requirements of 326 IAC 14-10-3 are mandatory. All demolition projects require notification whether or not asbestos is present.

- (b) The Permittee shall ensure that a written notification is sent on a form provided by the Commissioner at least ten (10) working days before asbestos stripping or removal work or before demolition begins, per 326 IAC 14-10-3, and shall update such notice as necessary, including, but not limited to the following:
 - (1) When the amount of affected asbestos containing material increases or decreases by at least twenty percent (20%); or
 - (2) If there is a change in the following:
 - (A) Asbestos removal or demolition start date;
 - (B) Removal or demolition contractor; or
 - (C) Waste disposal site.
- (c) The Permittee shall ensure that the notice is postmarked or delivered according to the guidelines set forth in 326 IAC 14-10-3(2).
- (d) The notice to be submitted shall include the information enumerated in 326 IAC 14-10-3(3).

All required notifications shall be submitted to:

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

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

- (e) **Procedures for Asbestos Emission Control**
The Permittee shall comply with the applicable emission control procedures in 326 IAC 14-10-4 and 40 CFR 61.145(c). Per 326 IAC 14-10-1, emission control requirements are applicable for any removal or disturbance of RACM greater than three (3) linear feet on pipes or three (3) square feet on any other facility components or a total of at least 0.75 cubic feet on all facility components.
- (f) **Demolition and Renovation**
The Permittee shall thoroughly inspect the affected facility or part of the facility where the demolition or renovation will occur for the presence of asbestos pursuant to 40 CFR 61.145(a).
- (g) **Indiana Licensed Asbestos Inspector**
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Licensed Asbestos Inspector to

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.8 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.9 Compliance Requirements [326 IAC 2-1.1-11]

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

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

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

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

- (a) When required by any condition of this permit, an analog instrument used to measure a parameter related to the operation of an air pollution control device shall have a scale such that the expected maximum reading for the normal range shall be no less than twenty percent (20%) of full scale. The analog instrument shall be capable of measuring values outside of the normal range.
- (b) The Permittee may request that the IDEM, OAQ approve the use of an instrument that does not meet the above specifications provided the Permittee can demonstrate that an alternative instrument specification will adequately ensure compliance with permit conditions requiring the measurement of the parameters.

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

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

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

- (a) The Permittee shall maintain the most recently submitted written emergency reduction plans (ERPs) consistent with safe operating procedures.
- (b) Upon direct notification by IDEM, OAQ that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

C.13 Risk Management Plan [326 IAC 2-7-5(12)] [40 CFR 68]

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

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

- (I) Upon detecting an excursion where a response step is required by the D Section, or an exceedance of a limitation, not subject to CAM, in this permit:
 - (a) The Permittee shall take reasonable response steps to restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing excess emissions.
 - (b) The response shall include minimizing the period of any startup, shutdown or malfunction. The response may include, but is not limited to, the following:
 - (1) initial inspection and evaluation;
 - (2) recording that operations returned or are returning to normal without operator action (such as through response by a computerized distribution control system); or
 - (3) any necessary follow-up actions to return operation to normal or usual manner of operation.
 - (c) A determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include, but is not limited to, the following:
 - (1) monitoring results;
 - (2) review of operation and maintenance procedures and records; and/or
 - (3) inspection of the control device, associated capture system, and the process.
 - (d) Failure to take reasonable response steps shall be considered a deviation from the permit.
 - (e) The Permittee shall record the reasonable response steps taken.
- (II)
 - (a) CAM Response to excursions or exceedances.
 - (1) Upon detecting an excursion or exceedance, subject to CAM, the Permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal

without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

- (2) Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.
- (b) If the Permittee identifies a failure to achieve compliance with an emission limitation, subject to CAM, or standard, subject to CAM, for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the IDEM, OAQ and, if necessary, submit a proposed significant permit modification to this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.
- (c) Based on the results of a determination made under paragraph (II)(a)(2) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a 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 Quality Improvement Plan (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.
 - (1) The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality

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

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

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

- (a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall submit a description of its response actions to IDEM, OAQ no later than seventy-five (75) days after the date of the test.
- (b) A retest to demonstrate compliance shall be performed no later than one hundred eighty (180) days after the date of the test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred eighty (180) days is not practicable, IDEM, OAQ may extend the retesting deadline.
- (c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

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

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

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

Pursuant to 326 IAC 2-6-3(b)(2), starting in 2005 and every three (3) years thereafter, the Permittee shall submit by July 1 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.17 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2][326 IAC 2-3]

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

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

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

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

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

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

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

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

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

- (ii) Projected actual emissions;
 - (iii) Amount of emissions excluded under section 326 IAC 2-2-1(pp)(2)(A)(iii) and/or 326 IAC 2-3-1 (kk)(2)(A)(iii); and
 - (iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.
- (d) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A) and/or 326 IAC 2-3-2 (l)(6)(A)) that a "project" (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:
- (1) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (1)(B) above; and
 - (2) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) years following resumption of regular operations after the change if the project increases the design capacity of or the potential to emit that regulated NSR pollutant at the emissions unit.

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

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

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

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

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

associated with zero and span or other daily calibration checks, if applicable);
and

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

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

- (b) The address for report submittal is:

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

- (c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.
- (d) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.
- (e) If the Permittee is required to comply with the recordkeeping provisions of (d) in Section C - General Record Keeping Requirements for any "project" (as defined in 326 IAC 2-2-1 (oo) and/or 326 IAC 2-3-1 (jj)) at an existing emissions unit, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:
 - (1) The annual emissions, in tons per year, from the project identified in (c)(1) in Section C- General Record Keeping Requirements exceed the baseline actual emissions, as documented and maintained under Section C- General Record Keeping Requirements (c)(1)(C)(i), by a significant amount, as defined in 326 IAC 2-2-1 (ww) and/or 326 IAC 2-3-1 (pp), for that regulated NSR pollutant, and
 - (2) The emissions differ from the preconstruction projection as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(ii).
- (f) The report for project at an existing emissions unit shall be submitted no later than sixty (60) days after the end of the year and contain the following:
 - (1) The name, address, and telephone number of the major stationary source.
 - (2) The annual emissions calculated in accordance with (d)(1) and (2) in Section C - General Record Keeping Requirements.
 - (3) The emissions calculated under the actual-to-projected actual test stated in 326 IAC 2-2-2(d)(3) and/or 326 IAC 2-3-2(c)(3).

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

Reports required in this part shall be submitted to:

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

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

Stratospheric Ozone Protection

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

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

Ambient Monitoring Requirements [326 IAC 7-3]

C.20 Ambient Monitoring [326 IAC 7-3]

- (a) The Permittee shall operate continuous ambient sulfur dioxide air quality monitors and a meteorological data acquisition system according to a monitoring plan submitted to the commissioner for approval. The monitoring plan shall include requirements listed in 326 IAC 7-3-2(a)(1), 326 IAC 7-3-2(a)(2) and 326 IAC 7-3-2(a)(3).
- (b) The Permittee and other operators subject to the requirements of this rule, located in the same county, may submit a joint monitoring plan to satisfy the requirements of this rule. [326 IAC 7-3-2(c)]
- (c) The Permittee may petition the commissioner for an administrative waiver of all or some of the requirements of 326 IAC 7-3 if such owner or operator can demonstrate that ambient monitoring is unnecessary to determine continued maintenance of the sulfur dioxide ambient air quality standards in the vicinity of the source. [326 IAC 7-3-2(d)]

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

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

Pursuant to PSD Permit PSD (26) 1215, issued March 17, 1978, particulate matter emissions (PM) from the Boiler No. 1 stack shall not exceed 0.12 pound per million Btu heat input (lb/MMBtu).

D.1.2 Sulfur Dioxide (SO₂) and Pollution Control Project [326 IAC 7-4-12.1][326 IAC 2-2.3] [326 IAC 2-3.3]

- (a) Pursuant to 326 IAC 7-4-12.1 (Gibson County Sulfur Dioxide Emission Limitations), the SO₂ emissions from Boiler No. 1 shall not exceed 3.19 pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.
- (b) Pursuant to 326 IAC 2-2.3 and 326 IAC 2-3.3, the installation and operation of the flue gas desulfurization (FGD) system for Boiler No. 1 and the associated limestone and gypsum handling equipment is considered a pollution control project.
- (c) Pursuant to 326 IAC 2-2.3 and 326 IAC 2-3.3, upon initial start up of the flue gas desulfurization (FGD) system, the sulfur dioxide (SO₂) emissions from Boiler No. 1 shall not exceed 1.0 pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.

D.1.3 Reserved

D.1.4 Preventive Maintenance Plan [326 IAC 1-6-3]

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

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

D.1.5 Reserved

D.1.6 Operation of Electrostatic Precipitator and Flue gas Desulfurization [326 IAC 2-7-6(6)]

- (a) Except as otherwise provided by statute or rule or in this permit, the electrostatic

precipitator shall be operated at all times that the Boiler No. 1 is in operation and combusting any amount of solid fuel or any combination of solid fuel and other fuels.

- (b) Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system shall be operated as needed to maintain compliance with applicable SO₂ emission limits.

D.1.7 Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

- (a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NO_x and SO₂ emissions.
- (b) All CEMS required by this permit shall meet all applicable performance specifications of 40 CFR 60 and 40 CFR 75 or any other applicable performance specifications, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.
- (c) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.
- (d) Whenever a continuous emission monitor is malfunctioning or is down for maintenance or repairs, the following shall be used as an alternative to continuous data collection:
 - (1) If the CEMS is required for monitoring NO_x emissions pursuant to 40 CFR 75 (Title IV Acid Rain program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D - Missing Data Substitution Procedures.
 - (2) If the CEMS is not used to monitor NO_x emissions from a unit subject to requirements of the Title IV Acid Rain program and is down for a period of four (4) hours or more, then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.
- (d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5, 40 CFR 60 and Construction Permit PSD (26) 1215.

D.1.8 Sulfur Dioxide Emissions [326 IAC 7-2][326 IAC 7-4-12.1][326 IAC 2-7-5(3)(A)][326 IAC 2-7-6]

- (a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide (SO₂) emissions do not exceed the equivalent of 3.19 pounds per MMBtu using a thirty (30) day rolling weighted average.
- (b) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7, coal sampling and analysis data shall be collected as follows:
 - (1) Coal sampling shall be performed using the methods specified in 326 IAC 3-7-2(a), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e); or
 - (2) Pursuant to 326 IAC 3-7-3, manual or other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring.

- (c) Upon written notification to IDEM by a facility owner or operator, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]
- (d) Pursuant to 326 IAC 3-5-1(c)(2)(B), compliance shall be demonstrated using SO₂ continuous emission monitoring system (CEMS) data.

D.1.9 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

The Permittee shall install, certify, maintain, and operate a CEMS measuring PM emissions discharged from Unit 1 scrubbed stack to the atmosphere and record the output of the system as specified in paragraphs (a) through (d):

- (a) The PM CEMS shall be installed, certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and 40 CFR 60.13(e).
- (b) Compliance with the applicable particulate emission limitation in Condition D.1.1 shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data.
- (c) For purposes of demonstrating compliance with the particulate emission limitation in Condition D.1.1, the Permittee shall adjust to 5% any measured carbon dioxide (CO₂) values that are below 5%.
- (d) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.
- (e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5 and Construction Permit PSD (26) 1215.

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

D.1.10 SO₂ Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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, slurry 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.

Flue gas desulfurization (FGD) parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a backup CEMS is brought online.

D.1.11 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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

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

- (1) the primary and secondary currents of the T-R sets.
- (2) the primary and secondary voltages of the T-R sets
- (3) daily number of TR sets in service

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

D.1.12 Record Keeping Requirement

- (a) To document the compliance status with Conditions D.1.1 - PSD BACT Requirements, D.1.6 - Operation of Electrostatic Precipitator and Flue gas Desulfurization, D.1.9~~8~~ - Particulate Matter (PM) Continuous Emission Monitoring System and D.1.11 - PM Monitoring System Downtime, the Permittee shall maintain records in accordance with (1) through (2) below.

Records shall be complete and sufficient to establish compliance with the limits in Condition D.1.1 - PSD BACT Requirements.

- (1) PM CEMS data to measure PM pursuant to t 326 IAC 3-5 and 326 IAC 7-2-1(g).
- (2) All ESP parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.1.11 - PM Monitoring System Downtime.

- (b) To document the compliance status with Conditions D.1.2 – Sulfur Dioxide (SO₂) and Pollution Control Project and Conditions D.1.1 - PSD BACT Requirements, , D.1.7 - Continuous Emissions Monitoring for, SO₂ and NO_x, Condition D.1.10 - SO₂ Monitor Downtime, the Permittee shall maintain records in accordance with (1) through (2) below.

Records shall be complete and sufficient to establish compliance with D.1.2 – Sulfur Dioxide (SO₂) and Pollution Control Project.

- (1) All SO₂ continuous emissions monitoring data pursuant to 326 IAC 3-5-6, and 326 IAC 7-2-1(g).
- (2) All flue gas desulfurization (FGD) system parametric monitoring readings taken during periods of CEMS down time, in accordance with Condition D.1.10 - SO₂ Monitoring Downtime.
- (3) To document the compliance status with Condition D.1.2, The Permittee shall keep records of the daily average coal sulfur content, coal heat content, weighting factor, and daily average sulfur dioxide emission rate in pounds per MMBtu.
- (4) To document the compliance status with Condition D.1.2, the Permittee shall keep records of the pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.

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

D.1.13 Reporting Requirement

- (a) A quarterly report shall be submitted not later than thirty (30) days following the end of each calendar quarter for PM, SO₂ and NO_x pursuant to this permit. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
- (b) Pursuant to 326 IAC 3-5-7(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) The Permittee shall report any PM, and SO₂ exceedances as part of its regular deviation reports.
- (d) To document compliance with Condition D.1.2, the Permittee shall submit quarterly reports of daily average sulfur content, coal heat content, daily average sulfur dioxide emission rate in lbs per MMBtu, and the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per MMBtu shall be submitted to the department in the quarterly report and maintained by the source owner or operator for a period of at least two (2) years.

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

(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 Requirements [326 IAC 2-2-3]

Pursuant to PSD Permit PSD (26) 1215, issued March 17, 1978, particulate matter emissions (PM) from the Boiler No. 2 stack shall not exceed 0.12 pound per million Btu heat input (lb/MMBtu).

D.2.2 Sulfur Dioxide (SO₂) and Pollution Control Project [326 IAC 7-4-12.1][326 IAC 2-2.3] [326 IAC 2-3.3]

- (a) Pursuant to 326 IAC 7-4-12.1 (Gibson County Sulfur Dioxide Emission Limitations), the SO₂ emissions from Boiler No. 2 shall not exceed 3.19 pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.
- (b) Pursuant to 326 IAC 2-2.3 and 326 IAC 2-3.3, the installation and operation of the flue gas desulfurization (FGD) system for Boiler No. 2 and the associated limestone and gypsum handling equipment is considered a pollution control project.
- (c) Pursuant to 326 IAC 2-2.3 and 326 IAC 2-3.3, upon initial start up of the flue gas desulfurization (FGD) system, the sulfur dioxide (SO₂) emissions from Boiler No. 2 shall not exceed 1.0 pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.

D.2.3 Reserved

D.2.4 Preventive Maintenance Plan [326 IAC 1-6-3]

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

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

D.2.5 Reserved

D.2.6 Operation of Electrostatic Precipitator and Flue Desulfurization (FGD) [326 IAC 2-7-6(6)]

- (a) Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator shall be operated at all times that the Boiler No. 2 is in operation and combusting any amount of solid fuel or any combination of solid fuel and other fuels.
- (b) Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system shall be operated as needed to maintain compliance with applicable SO₂ emission limits.

D.2.7 Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

- (a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NO_x and SO₂ emissions.
- (b) All CEMS required by this permit shall meet all applicable performance specifications of 40 CFR 60 and 40 CFR 75 or any other applicable performance specifications, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.
- (c) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.
- (d) Whenever a continuous emission monitor is malfunctioning or is down for maintenance or repairs, the following shall be used as an alternative to continuous data collection:
 - (1) If the CEMS is required for monitoring NO_x emissions pursuant to 40 CFR 75 (Title IV Acid Rain program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D - Missing Data Substitution Procedures.
 - (2) If the CEMS is not used to monitor NO_x emissions from a unit subject to requirements of the Title IV Acid Rain program and is down for a period of four (4) hours or more, then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.
- (d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5, 40 CFR 60 and Construction Permit PSD (26) 1215.

D.2.8 Sulfur Dioxide Emissions [326 IAC 7-2][326 IAC 7-4-12.1][326 IAC 2-7-5(3)(A)][326 IAC 2-7-6]

- (a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide (SO₂) emissions do not exceed the equivalent of 3.19 pounds per MMBtu using a thirty (30) day rolling weighted average.
- (b) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7, coal sampling and analysis data shall be collected as follows:
 - (1) Coal sampling shall be performed using the methods specified in 326 IAC 3-7-2(a), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e); or
 - (2) Pursuant to 326 IAC 3-7-3, manual or other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis

procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring.

- (c) Upon written notification to IDEM by a facility owner or operator, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]
- (d) Pursuant to 326 IAC 3-5-1(c)(2)(B), compliance shall be demonstrated using SO₂ continuous emission monitoring system (CEMS) data.

D.2.9 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

The Permittee shall install, certify, maintain, and operate a CEMS measuring PM emissions discharged from Unit 2 scrubbed stack to the atmosphere and record the output of the system as specified in paragraphs (a) through (d):

- (a) The PM CEMS shall be installed, certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and 40 CFR 60.13(e).
- (b) Compliance with the applicable particulate emission limitation in Condition D.2.1 shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data.
- (c) For purposes of demonstrating compliance with the particulate emission limitation in Condition D.2.1, the Permittee shall adjust to 5% any measured carbon dioxide (CO₂) values that are below 5%.
- (d) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.
- (e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5 and Construction Permit PSD (26) 1215.

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

D.2.10 SO₂ Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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, slurry 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.

Flue gas desulfurization (FGD) parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a backup CEMS is brought online.

D.2.11 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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

- (a) The ability of the electrostatic precipitator to control particulate matter

emissions shall be monitored once per day when Unit 1 is in operation by measuring and recording the following:

- (1) the primary and secondary currents of the T-R sets.
- (2) the primary and secondary voltages of the T-R sets
- (3) daily number of TR sets in service

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

D.2.12 Record Keeping Requirement

- (a) To document the compliance status with, Conditions D.2.1 - PSD BACT Requirements, D.2.6 - Operation of Electrostatic Precipitator and Flue Desulfurization (FGD), D.2.9 - Particulate Matter (PM) Continuous Emission Monitoring System and D.2.11 - PM Monitoring System Downtime. Permittee shall maintain records in accordance with (1) through (2) below.
 - (1) PM CEMS data when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit and 326 IAC 3-5.
 - (2) All ESP parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.2.11 - PM Monitoring System Downtime
- (b) To document the compliance status with and Condition D.2.2 Sulfur Dioxide (SO₂) and Pollution Control Project, D.2.7 - Continuous Emissions Monitoring for SO₂ and NO_x, Condition D.2.8- Sulfur Dioxide Emissions and Condition D.1.10 SO₂ Monitor Downtime the Permittee shall maintain records in accordance with (1) through (5) below.

Records shall be complete and sufficient to establish compliance with the limits established in SO₂ limits in Conditions D.2. 2

- (1) All SO₂ continuous emissions monitoring data pursuant to 326 IAC 3-5-6, and 326 IAC 7-2-1(g).
- (2) All flue gas desulfurization (FGD) system parametric monitoring readings taken during periods of CEMS down time, in accordance with Condition D.2.10 - SO₂ Monitoring Downtime.
- (3) To document the compliance status with Condition D.2.2, The Permittee shall keep records of the daily average coal sulfur content, coal heat content, weighting factor, and daily average sulfur dioxide emission rate in pounds per MMBtu.
- (4) To document the compliance status with Condition D.2.2, the Permittee shall keep records of the pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.
- (c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.2.13 Reporting Requirement

- (a) A quarterly report shall be submitted not later than thirty (30) days following the end of each calendar quarter for PM, SO₂ and NO_x pursuant to this permit. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
- (b) Pursuant to 326 IAC 3-5-7(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) The permittee shall report any PM, and SO₂ exceedances as part of its regular deviation report
- (d) To document compliance with Condition D.2.2, the Permittee shall submit quarterly reports of daily average sulfur content, coal heat content, daily average sulfur dioxide emission rate in lbs per MMBtu, and the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per MMBtu shall be submitted to the department in the quarterly report and maintained by the source owner or operator for a period of at least two (2) years.

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

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

Pursuant to PSD Permit PSD (26) 1215, issued March 17, 1978, particulate matter emissions (PM) from the Boiler No. 3 stack shall not exceed 0.12 pound per million Btu heat input (lb/MMBtu).

D.3.2 Sulfur Dioxide (SO₂) and Pollution Control Project [326 IAC 7-4-12.1][326 IAC 2-2.3] [326 IAC 2-3.3]

- (a) Pursuant to 326 IAC 7-4-12.1 (Gibson County Sulfur Dioxide Emission Limitations), the SO₂ emissions from Boiler No. 3 shall not exceed 3.19 pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.
- (b) Pursuant to 326 IAC 2-2.3 and 326 IAC 2-3.3, the installation and operation of the flue gas desulfurization (FGD) system for Boiler No. 3 and the associated limestone and gypsum handling equipment is considered a pollution control project.
- (c) Pursuant to 326 IAC 2-2.3 and 326 IAC 2-3.3, upon initial start up of the flue gas desulfurization (FGD) system, the sulfur dioxide (SO₂) emissions from Boiler No. 3 shall not exceed 1.5 pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.

D.3.3 Reserved

D.3.4 Preventive Maintenance Plan [326 IAC 1-6-3]

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

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

D.3.5 Reserved

D.3.6 Operation of Electrostatic Precipitator and Flue Gas Desulfurization (FGD) [326 IAC 2-7-6(6)]

- (a) Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator shall be operated at all times that the Boiler No. 3 is in operation and combusting any amount of solid fuel or any combination of solid fuel and other fuels.
- (b) Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system shall be operated as needed to maintain compliance with applicable SO₂ emission limits.

D.3.7 Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

- (a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NO_x and SO₂ emissions.
- (b) All CEMS required by this permit shall meet all applicable performance specifications of 40 CFR 60 and 40 CFR 75 or any other applicable performance specifications, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.
- (c) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.
- (d) Whenever a continuous emission monitor is malfunctioning or is down for maintenance or repairs, the following shall be used as an alternative to continuous data collection:
 - (1) If the CEMS is required for monitoring NO_x emissions pursuant to 40 CFR 75 (Title IV Acid Rain program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D - Missing Data Substitution Procedures.
 - (2) If the CEMS is not used to monitor NO_x emissions from a unit subject to requirements of the Title IV Acid Rain program and is down for a period of four (4) hours or more, then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.
- (d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5, 40 CFR 60 and Construction Permit PSD (26) 1215.

D.3.8 Sulfur Dioxide Emissions [326 IAC 7-2][326 IAC 7-4-12.1][326 IAC 2-7-5(3)(A)][326 IAC 2-7-6]

- (a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide (SO₂) emissions do not exceed the equivalent of 3.19 pounds per MMBtu using a thirty (30) day rolling weighted average.
- (b) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7, coal sampling and analysis data shall be collected as follows:
 - (1) Coal sampling shall be performed using the methods specified in 326 IAC 3-7-2(a), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e); or
 - (2) Pursuant to 326 IAC 3-7-3, manual or other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission

estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring.

- (c) Upon written notification to IDEM by a facility owner or operator, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]
- (d) Pursuant to 326 IAC 3-5-1(c)(2)(B), compliance shall be demonstrated using SO₂ continuous emission monitoring system (CEMS) data.

D.3.9 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

The Permittee shall install, certify, maintain, and operate a CEMS measuring PM emissions discharged from Unit 3 scrubbed stack to the atmosphere and record the output of the system as specified in paragraphs (a) through (d):

- (a) The PM CEMS shall be installed, certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and 40 CFR 60.13(e).
- (b) Compliance with the applicable particulate emission limitation in Condition D.3.1 shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data.
- (c) For purposes of demonstrating compliance with the particulate emission limitation in Condition D.3.1, the Permittee shall adjust to 5% any measured carbon dioxide (CO₂) values that are below 5%.
- (d) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.
- (e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5 and Construction Permit PSD (26) 1215.

D.3.10 SO₂ Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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, slurry 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.

Flue gas desulfurization (FGD) parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a backup CEMS is brought online.

D.3.11 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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

- (a) The ability of the electrostatic precipitator to control particulate matter emissions shall

be monitored once per day when Unit 1 is in operation by measuring and recording the following:

- (1) the primary and secondary currents of the T-R sets.
- (2) the primary and secondary voltages of the T-R sets
- (3) daily number of TR sets in service

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

D.3.12 Record Keeping Requirements

- (a) To document the compliance status with Section C - Opacity and Conditions D.3.1 - PSD BACT Requirements, D.3.6 - Operation of Electrostatic Precipitator and Flue Gas Desulfurization (FGD), D.3.9 - Particulate Matter (PM) Continuous Emission Monitoring System and D.3.11 - PM Monitoring System Downtime, the Permittee shall maintain records in accordance with (1) through (2) below.

Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.3.1 - PSD BACT Requirements:

- (1) PM CEMS data when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit and 326 IAC 3-5.
 - (2) All ESP parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.2.11 - PM Monitoring System Downtime.
- (b) To document the compliance status with, Conditions D.3.2 Sulfur Dioxide (SO₂) and Pollution Control Project, D.3.7 - Continuous Emissions Monitoring for SO₂ and NO_x, Condition 3.8 - Sulfur Dioxide Emissions, Condition D.3.10 - SO₂ Monitor Downtime the Permittee shall maintain records in accordance with (1) through (2) below. Records shall be complete and sufficient to establish compliance with the SO₂ limit established in conditions D.3.2
- (1) All SO₂ continuous emissions monitoring data pursuant to 326 IAC 3-5-6, and 326 IAC 7-2-1(g).
 - (2) All flue gas desulfurization (FGD) system parametric monitoring readings taken during periods of CEMS down time, in accordance with Condition D.3.10 - SO₂ Monitoring Downtime.
 - (3) To document the compliance status with Condition D.3.2, The Permittee shall keep records of the daily average coal sulfur content, coal heat content, weighting factor, and daily average sulfur dioxide emission rate in pounds per MMBtu.
 - (5) To document the compliance status with Condition D.3.2, the Permittee shall keep records of the pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.

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

D.3.12 Reporting Requirement

- (a) A quarterly report shall be submitted not later than thirty (30) days following the end of each calendar quarter for PM, SO₂ and NO_x pursuant to this permit. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
- (b) Pursuant to 326 IAC 3-5-7(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) The permittee shall report any PM, and SO₂ exceedances as part of its regular deviation reports.
- (d) To document compliance with Condition D.3.2, the Permittee shall submit quarterly reports of daily average sulfur content, coal heat content, daily average sulfur dioxide emission rate in lbs per MMBtu, and the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per MMBtu shall be submitted to the department in the quarterly report and maintained by the source owner or operator for a period of at least two (2) years.

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NOx during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack D.

Boiler No. 4 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

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

Pursuant to PSD Permit PSD (26) 1215, issued March 17, 1978, particulate matter emissions (PM) from the Boiler No. 4 stack shall not exceed 0.12 pound per million Btu heat input (lb/MMBtu).

D.4.2 Sulfur Dioxide (SO₂) Limitations [326 IAC 7-4-12.1]

Pursuant to 326 IAC 7-4-12.1 (Gibson County Sulfur Dioxide Emission Limitations), the SO₂ emissions from Boiler No. 4 stack shall not exceed 0.60 pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average and operate an FGD system.

D.4.3 Reserved

D.4.4 Preventive Maintenance Plan [326 IAC 1-6-3]

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

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

D.4.5 Reserved

D.4.6 Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator shall be operated at all times that the Boiler No. 4 is in operation and combusting any amount of solid fuel or any combination of solid fuel and other fuels.

D.4.7 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 shall be operated as needed to maintain compliance with applicable SO₂ emission limits.

D.4.8 Maintenance of Continuous Emission Monitoring System for SO₂ and NOx [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

- (a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NOx and SO₂ emissions.

- (b) All CEMS required by this permit shall meet all applicable performance specifications of 40 CFR 60 and 40 CFR 75 or any other applicable performance specifications, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.
- (c) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.
- (d) Whenever a continuous emission monitor is malfunctioning or is down for maintenance or repairs, the following shall be used as an alternative to continuous data collection:
 - (1) If the CEMS is required for monitoring NOX emissions pursuant to 40 CFR 75 (Title IV Acid Rain program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D - Missing Data Substitution Procedures.
 - (2) If the CEMS is not used to monitor NOx emissions from a unit subject to requirements of the Title IV Acid Rain program and is down for a period of four (4) hours or more, then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.
- (d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5, 40 CFR 60 and Construction Permit PSD (26) 1215.

D.4.9 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

The Permittee shall install, certify, maintain, and operate a CEMS measuring PM emissions discharged from Unit 4 scrubbed stack to the atmosphere and record the output of the system as specified in paragraphs (a) through (d):

- (a) The PM CEMS shall be installed, certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and 40 CFR 60.13(e).
- (b) Compliance with the applicable particulate emission limitation in Condition D.4.1 shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data.
- (c) For purposes of demonstrating compliance with the particulate emission limitation in Condition D.4.1, the Permittee shall adjust to 5% any measured carbon dioxide (CO2) values that are below 5%.
- (d) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.
- (e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5 and Construction Permit PSD (26) 1215.

D.4.10 Sulfur Dioxide Emissions [326 IAC 2-7-5(3)(A)][326 IAC 2-7-6][326 IAC 3-5]

Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions from Unit 4 does not exceed the equivalents of the limits specified in Condition D.4.2 - Sulfur Dioxide (SO₂), using a thirty (30) day rolling weighted average.

Pursuant to 326 IAC 3-5-1(c)(2)(B), compliance shall be demonstrated using CEMS data.

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

D.4.11 SO₂ Monitor System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(1)]

Whenever 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, slurry feed rate, and number of recirculation pumps in service, to demonstrate that the operation of the flue gas desulfurization (FGD) system continues in a manner typical for the boiler load and sulfur content of the coal fired.

Flue gas desulfurization (FGD) system parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a backup CEMS is brought online.

D.4.12 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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

- (a) The ability of the electrostatic precipitator to control particulate matter emissions shall be monitored once per day when Unit 1 is in operation by measuring and recording the following:
- (1) the primary and secondary currents of the T-R sets.
 - (2) the primary and secondary voltages of the T-R sets
 - (3) daily number of TR sets in service

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

D.4.13 Record Keeping Requirements

- (a) To document the compliance status with Section C - Opacity and Conditions D.4.1 - PSD BACT Requirements, D.4.6 - Operation of Electrostatic Precipitator, D.4.9 - Particulate Matter (PM) Continuous Emission Monitoring System and D.4.12 - PM Monitoring System Downtime-the Permittee shall maintain records in accordance with (1) through (2) below.

Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.4.1 - PSD BACT Requirements:

- (1) PM CEMS data when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit and 326 IAC 3-5.
 - (2) All ESP parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.4.12 - PM Monitoring System Downtime.
- (b) To document the compliance status with SO₂ Conditions D.4.2 - Sulfur Dioxide (SO₂) Sulfur Limitations, D.4.9 - Continuous Emissions Monitoring for SO₂ and NO_x, D.4.11 -

Sulfur Dioxide Emissions, D.4.7 ~~D.4.8~~ - Flue Gas Desulfurization (FGD) System, and D.4.11 - SO₂ Monitor Downtime, the Permittee shall maintain records in accordance with (1) and (2) below.

Records shall be complete and sufficient to establish compliance with the SO₂ limits as required in Conditions D.4.2 - Sulfur Dioxide (SO₂), and D.4.11 - Sulfur Dioxide Emissions. The Permittee shall maintain records in accordance with (2) ~~and (3)~~ below during SO₂ CEMS system downtime if a backup CEMS is not used.

- (1) All SO₂ continuous emissions monitoring data, pursuant to 326 IAC 7-2-1(g) and 326 IAC 3-5,
 - (2) All flue gas desulfurization (FGD) system parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.4.15- SO₂ Monitor Downtime.
 - (3) To document the compliance status with Condition D.4.2, The Permittee shall keep records of the daily average coal sulfur content, coal heat content, weighting factor, and daily average sulfur dioxide emission rate in pounds per MMBtu.
 - (6) To document the compliance status with Condition D.4.2, the Permittee shall keep records of the pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.
- (c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.4.14 Reporting Requirements

- (a) A quarterly report and a quarterly summary of the information shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar for PM, SO₂ and NO_x pursuant to this permit. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
- (b) Pursuant to 326 IAC 3-5-7(5), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
 - (1) Date of downtime.
 - (2) Time of commencement.
 - (3) Duration of each downtime.
 - (4) Reasons for each downtime.
 - (5) Nature of system repairs and adjustments.

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

- (c) The permittee shall report any PM, and SO₂ exceedances as part of its regular deviation reports.

- (d) To document compliance with Condition D.4.2, the Permittee shall submit quarterly reports of daily average sulfur content, coal heat content, daily average sulfur dioxide emission rate in lbs per MMBtu, and the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per MMBtu shall be submitted to the department in the quarterly report and maintained by the source owner or operator for a period of at least two (2) years.

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 5.

Boiler No. 5 has continuous emissions monitors (CEMS) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

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

Pursuant to Construction Permit PSD (26) 1215 issued on March 17, 1978, 326 IAC 2-2 the and 40 CFR 52.21 (Prevention of Significant Deterioration), PM emissions from the Boiler No. 5 stack 5 shall not exceed one-tenth (0.10) pound PM per million Btu (MMBtu) heat input.

D.5.2 Sulfur Dioxide (SO₂) Limitations [326 IAC 7-4-12.1]

Pursuant to 326 IAC 7-4-12.1 (Gibson County Sulfur Dioxide Emission Limitations), the SO₂ emissions from Boiler No. 5 stack shall not exceed 1.10 pounds per million Btu (lbs/MMBtu) based on a twenty-four (24) hour average and operation of an FGD system.

D.5.3 Reserved

D.5.4 Preventive Maintenance Plan [326 IAC 1-6-3]

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

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

D.5.5 Reserved

D.5.6 Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator shall be operated at all times that the Boiler No. 5 is in operation and combusting any amount of solid fuel or any combination of solid fuel and other fuels.

D.5.7 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 shall be operated as needed to maintain compliance with applicable SO₂ emission limits.

D.5.8 Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

- (a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NO_x and SO₂ emissions.

- (b) All CEMS required by this permit shall meet all applicable performance specifications of 40 CFR 60 and 40 CFR 75 or any other applicable performance specifications, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.
- (c) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.
- (d) Whenever a continuous emission monitor other than an opacity monitor is malfunctioning or is down for maintenance or repairs, the following shall be used as an alternative to continuous data collection:
 - (1) If the CEMS is required for monitoring NOX emissions pursuant to 40 CFR 75 (Title IV Acid Rain program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D - Missing Data Substitution Procedures.
 - (2) If the CEMS is not used to monitor NOx emissions from a unit subject to requirements of the Title IV Acid Rain program and is down for a period of four (4) hours or more, then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.
- (d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5, 40 CFR 60 and Construction Permit PSD (26) 1215.

D.5.9 Sulfur Dioxide Emissions [326 IAC 2-7-5(3)(A)][326 IAC 2-7-6][326 IAC 3-5]

Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions from Unit 5 does not exceed the limits specified in Conditions D.5.2 - Sulfur Dioxide (SO₂), using a thirty (30) day rolling weighted average.

Pursuant to 326 IAC 3-5-1(c)(2)(B), compliance shall be demonstrated using CEMS data.

D.5.10 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

The Permittee shall install, certify, maintain, and operate a CEMS measuring PM emissions discharged from Unit 5 scrubbed stack to the atmosphere and record the output of the system as specified in paragraphs (a) through (d):

- (a) The PM CEMS shall be installed, certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and 40 CFR 60.13(e).
- (b) Compliance with the applicable particulate emission limitation in Condition D.5.1 shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data.
- (c) For purposes of demonstrating compliance with the particulate emission limitation in Condition D.5.1, the Permittee shall adjust to 5% any measured carbon dioxide (CO₂) values that are below 5%.
- (d) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

- (e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5 and Construction Permit PSD (26) 1215.

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

D.5.11 SO₂ Monitor System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(1)]

Whenever 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, slurry feed rate, and number of recirculation pumps in service, to demonstrate that the operation of the flue gas desulfurization (FGD) system continues in a manner typical for the boiler load and sulfur content of the coal fired.

Flue gas desulfurization (FGD) system parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a backup CEMS is brought online.

D.5.12 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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

- (a) The ability of the electrostatic precipitator to control particulate matter emissions shall be monitored once per day when Unit 1 is in operation by measuring and recording the following:
- (1) the primary and secondary currents of the T-R sets.
 - (2) the primary and secondary voltages of the T-R sets
 - (3) daily number of TR sets in service

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

D.5.13 Record Keeping Requirements

- (a) To document the compliance status with Section C - Opacity and Conditions D.5.1 - PSD BACT Requirements, D.5.6 - Operation of Electrostatic Precipitator, D.5.10 - Continuous Emissions Monitoring for PM, Condition D.5.12 - PM Monitoring System Downtime and the Permittee shall maintain records in accordance with (1) through (2) below.

Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.5.1 - PSD BACT Requirements:

- (1) PM CEMS data when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.
 - (2) All ESP parametric monitoring readings.
- (b) To document the compliance status with Conditions D.5.2 - Sulfur Dioxide (SO₂), D.5.7 - Flue Gas Desulfurization (FGD) System, D.5.10 - Continuous Emissions Monitoring for SO₂ and NO_x, D.5.11 - Sulfur Dioxide Emissions, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the SO₂ limits as required in Conditions D.5.2 - Sulfur Dioxide (SO₂), and D.5.7 - Flue Gas Desulfurization (FGD) System. The Permittee shall maintain records in accordance with (2) below during SO₂ CEMS system downtime if a backup CEMS is not used.

- (1) All SO₂ continuous emissions monitoring data, pursuant to 326 IAC 7-2-1(g) and 40 CFR 60.40 (Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971), with calendar dates and beginning and ending times of any CEMS downtime.
 - (2) All flue gas desulfurization (FGD) system parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.5.12 - SO₂ Monitor Downtime.
 - (3) To document the compliance status with Condition D.5.2, The Permittee shall keep records of the daily average coal sulfur content, coal heat content, weighting factor, and daily average sulfur dioxide emission rate in pounds per MMBtu.
 - (7) To document the compliance status with Condition D.5.2, the Permittee shall keep records of the pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.
- (c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.5.14 Reporting Requirements

- (a) A quarterly report and a quarterly summary of the information to document the compliance status with Condition D.5.2 - Sulfur Dioxide (SO₂), shall be submitted not later than thirty (30) days following the end of each calendar quarter for PM, SO₂ and NO_x pursuant to this permit. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
- (b) Pursuant to 326 IAC 3-5-7(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) The permittee shall report any PM, and SO₂ exceedances as part of its regular deviation reports.
- (d) To document compliance with Condition D.5.2, the Permittee shall submit quarterly reports of daily average sulfur content, coal heat content, daily average sulfur dioxide emission rate in lbs per MMBtu, and the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per MMBtu shall be submitted to the department in the

quarterly report and maintained by the source owner or operator for a period of at least two (2) years.

D.5.15 ORDER of the Commissioner of the Indiana Department of Environmental Management

Pursuant to Indiana Code § 13-14-2-6 and in order to secure compliance with 40 CFR Part 63, Subpart UUUUU, Duke Energy, Inc. - Gibson Generating Station is subject to following ORDER:

1. Duke Energy, Inc. - Gibson Generating Station shall submit a status report within fifteen (15) days of completion of the following milestones indicating the actual dates of completion:
 - a. The date on-site construction for the installation of the emission control equipment identified in Attachment F for Gibson Unit 5 is initiated, and
 - b. The date on-site construction for the installation of the emission control equipment identified in Attachment F for Gibson Unit 5 is completed.
 - c. The date by which final compliance with 40 CFR 63, Subpart UUUUU for Gibson Unit 5 is achieved.
2. Duke Energy, Inc. - Gibson Generating Station Unit 5 shall comply with the HCL and PM compliance demonstration standards set forth in 40 CFR Part 63, Subpart UUUUU no later than April 16, 2016.
3. Duke Energy Indiana shall request a significant permit modification of its Part 70 permit pursuant to 326 IAC 2-7-12 within twelve (12) months of the date of this order to add the compliance schedule requirements contained in Order Paragraphs 1 and 2

Upon the effective date of this Order, all terms of the October 11, 2012 Order referenced above is no longer in effect.

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (f) A coal transfer system, with a nominal throughput of 6,000 tons of coal per hour, consisting of the following equipment:
- (1) Two (2) railcar unloading stations, each with a drop point to a hopper identified as DP-5 and DP-25, with the drop point controlled by a partial enclosure, and exhausting to the ambient air.
 - (2) Two (2) active piles, each with a drop point to a hopper identified as DP-1 and DP-16, with each drop point enclosed and exhausting to the ambient air.
 - (3) Three (3) storage piles, having an estimated combined storage capacity including the active piles of 4,000,000 tons, with fugitive emissions controlled by watering trucks.
 - (4) Four (4) enclosed hoppers, each with a drop point to conveyors identified as DP-2, DP-6, DP-17 and DP-26, with each drop point enclosed and exhausting to the ambient air.
 - (5) An enclosed conveyor system, with 18 drop points identified as DP-3, DP-4, DP-7 through DP-15, and DP-14 through DP-22, with each drop point enclosed, excluding the two (2) active pile conveyors which have the drop points (DP-18 and DP-22) controlled by either telescopic chutes or a dust suppression system, and exhausting to the ambient air.
 - (6) Five (5) enclosed coal bunkers, each with a nominal capacity of 15,000 tons of coal. Bunkers are loaded via a conveyor tripper system with a total capacity of 3,000 tons per hour to the units 1 and 2 bunkers, and 3,000 tons per hour to the units 3, 4 and 5 bunkers.

(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 (Particulate Emission Limitations for Manufacturing Processes), the particulate emissions from the coal storage and handling drop points and coal bunkers shall not exceed 103.2 pounds per hour when operating at a process weight of 6000 tons per hour. This is determined by the following equation:

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

$$E = 55.0 P^{0.11} - 40$$

Where:

E = rate of emission in pounds per hour; and
 P = 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 103.2 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.

D.6.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for the emissions units, the watering system and the telescopic. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

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

D.6.3 Particulate Control [326 IAC 2-7-6(6)]

Telescoping chutes shall be kept within a few feet of the top of the coal piles at all times drop points DP-14 and DP-22 are in operation.

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

D.6.4 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

- (a) Visible emission notations of the transfer points shall be performed once per week during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

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

- (b) Visible emission notations of the coal unloading station(s) doorways and drop points shall be performed once per week during normal daylight operations. A trained employee shall record whether any emissions are observed.

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

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

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

D.6.5 Record Keeping Requirements

- (a) To document the compliance status with Condition D.6.4 - Visible Emissions Notations, the Permittee shall maintain records of the weekly visible emission notations of the transfer points, railcar unloading stations and all response steps taken and the outcome

for each. The Permittee shall include in its records when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g., the process did not operate that day).

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

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (g) A limestone processing system, consisting of the following equipment:
- (1) One (1) unloading station for trucks or railcar, with a drop point to a hopper identified as LSDP-1 with a nominal throughput of 2,500 tons of limestone per hour, with the drop point controlled by a partial enclosure, and exhausting to the ambient air.
 - (2) Two (2) enclosed hoppers, each with a drop point to conveyors identified as LSDP-2 and LSDP-5 with a nominal throughput of 200 tons of limestone per hour, with each drop point enclosed.
 - (3) One (1) storage pile, with a nominal storage capacity of 50,000 tons, with a drop point to a hopper identified as LSDP-4, with the drop point enclosed and exhausting to the ambient air.
 - (4) An enclosed conveyor system, with four (4) drop points identified as LSDP-3 and LSDP-8 through LSDP-10, with each drop point enclosed.
 - (5) One (1) enclosed ball mill, with a drop point to a conveyor identified as LSDP-6, with the drop point enclosed.
 - (6) Two (2) day bins for temporary storage of limestone, with a combined storage capacity of 13,000 tons, with dust from loading the bins controlled by bin vent filters, and exhausting to the ambient air.

(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 storage and handling drop points and bunkers shall not exceed 61 pounds per hour when operating at a process weight of 250 tons per hour. This is determined by the following equation:

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

$$E = 55.0 P^{0.11} - 40 \quad \text{where } E = \text{rate of emission in pounds per hour; and} \\ P = \text{process weight rate in tons per hour.}$$

When the process weight rate exceeds two hundred (200) tons per hour, the maximum allowable emission may exceed 61 pounds per hour, provided the concentration of particulate matter in the discharge gases to the atmosphere is less than 0.10 pounds per one thousand (1,000) pounds of gases.

D.7.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for the emissions units, watering system and the telescopic. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

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

D.7.2 Particulate Control [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, to demonstrate compliance with 326 IAC 6-3-2:

The telescopic chute for all conveyors shall be kept within a few feet of the top of the limestone piles at all times the limestone handling system is in operation.

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

D.7.3 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

- (a) Visible emission notations of the transfer points and ball mill baghouse exhausts shall be performed once per week during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

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

- (b) Visible emission notations of the partially enclosed railcar limestone unloading station exhausts shall be performed once per week during normal daylight operations. A trained employee shall record whether any emissions are observed.

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

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

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

- (d) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation.
- (e) 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.
- (f) A trained employee is an employee who has worked at the plant at least one (1) month

and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

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 Condition D.7.3 - Visible Emissions Notations, the Permittee shall maintain records of the weekly visible emission notations of the transfer points, limestone unloading station doors, fly ash storage pond area(s) and all response steps taken and the outcome for each. The Permittee shall include in its records when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g., the process did not operate that day).
- (b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (h) Limestone Handling (TP-1 to TP-5, TP-10 to TP-17, F-6 and F-9), with maximum capacity of 2,500 tons per hour:
- (1) Transfer of limestone from railcar or truck to the limestone hopper, with fogging type dust suppression as particulate control.
 - (2) Enclosed transfer of limestone from unloading hoppers to belt feeders.
 - (3) Enclosed transfer of limestone from belt feeders to conveyors.
 - (4) Telescoping chute transfer of limestone from conveyor to lime storage stockout pile.
 - (5) Enclosed transfer of limestone from the reclaim hoppers to belt feeders, with fogging type dust suppression as particulate control.
 - (6) Enclosed transfer of limestone from conveyor to conveyor, with fogging type dust suppression as particulate control.
 - (7) Transfer of limestone from conveyor to day bin, with surge-bin filter as particulate control.
 - (8) Enclosed transfer of limestone from conveyor fixed hopper to conveyor with fogging type dust suppression as particulate control.
 - (9) Transfer of limestone from conveyor fixed tripper to day bin, with surge-bin filter as particulate control.
 - (10) Limestone storage piles, with watering type dust suppression as fugitive dust control.

(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 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 gypsum handling operation shall not exceed 90 pounds per hour when operating at a process weight of 2500 tons per hour. This is determined by the following equation:

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

$$E = 55.0 P^{0.11} - 40 \quad \text{where } E = \text{rate of emission in pounds per hour; and} \\ P = \text{process weight rate in tons per hour.}$$

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

D.8.2 Preventive Maintenance Plan (PMP) [326 IAC 2-7-5(13)]

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

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

D.8.3 Particulate Control [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit:

- (a) The Permittee shall apply fogging type dust suppression when the following are in operation:
 - transfers of limestone from railcar or truck to the limestone hopper,
 - transfers of limestone from conveyor to conveyor, and
 - transfers of limestone from conveyor fixed hopper to conveyor.
- (b) The Permittee shall conduct the transfers of limestone in enclosures when the following are in operation:
 - from unloading hoppers to belt feeders,
 - from belt feeders to conveyors,
 - from the reclaim hoppers to belt feeders,
 - from conveyor to conveyor, and
 - from conveyor fixed hopper to conveyor.
- (c) The Permittee shall use surge-bin filters when the following are in operation:
 - transfers of limestone from conveyor to day bin.
 - transfers of limestone from conveyor fixed tripper to day bin.
- (d) The Permittee shall use telescoping chute transfer of limestone from conveyor to lime storage stockout pile.

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

D.8.4 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

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

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

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

D.8.5 Record Keeping Requirement

- (a) To document the compliance status with Condition D.8.4, the Permittee shall maintain records of the weekly visible emission notations of the limestone transfer points, and all response steps taken and the outcome for each and make such records available upon request to IDEM, OAQ, and the US EPA. The Permittee shall include in its records when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g., the process did not operate that day).
- (b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (i) Gypsum Handling (TP-26 to TP-35, TP-38, and TP-39), with maximum capacity of 300 tons per hour:
- (1) Enclosed transfer of gypsum from belt feeders to conveyors.
 - (2) Transfer of gypsum from conveyors to stockout piles.
 - (3) Partially enclosed transfer of gypsum from conveyor to radial stacker conveyor.
 - (4) Transfer of gypsum from radial stacker conveyor to stockout pile.
 - (5) Stockout piles.

(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.9.1 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 gypsum handling operation shall not exceed 63 pounds per hour when operating at a process weight of 300 tons per hour. This is determined by the following equation:

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

$$E = 55.0 P^{0.11} - 40 \quad \text{where } E = \text{rate of emission in pounds per hour; and} \\ P = \text{process weight rate in tons per hour.}$$

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

D.9.2 Preventive Maintenance Plan (PMP) [326 IAC 2-7-5(13)]

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

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

D.9.3 Particulate Control [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit:

- (a) The Permittee shall conduct the transfers of gypsum from belt feeders to conveyors in enclosures.
- (b) The Permittee shall conduct transfers of gypsum from conveyor to radial stacker conveyor in a partial enclosure.

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

D.9.4 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

- (a) Visible emission notations of the gypsum transfer points 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.
- (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 visible emissions are observed crossing the property line or boundaries of the property, right-of-way, or easement on which the source is located, the Permittee shall take reasonable response. Failure to take response steps, shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.
- (f) If abnormal emissions are observed from the gypsum transfer points, the Permittee shall take reasonable response steps. Observation of abnormal emissions that do not violate 326 IAC 6-4 (Fugitive Dust Emissions) or an applicable opacity limit is not a deviation from this permit. Failure to take response steps, shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

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

D.9.5 Record Keeping Requirements

- (a) To document the compliance status with Condition D.9.4, the Permittee shall maintain records of the once per week visible emission notations of the gypsum transfer points, and all response steps taken and the outcome for each and make such records available upon request to IDEM, OAQ, and the US EPA. The Permittee shall include in its records when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g., the process did not operate that day).
- (b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (j) Dry fly ash handling system, including the following, permitted in 2011:
- (1) one (1) pneumatic fly ash transfer system from existing precipitator hoppers for Units 1, 2, and 3 equipped with separators/exhausters designated as 1A, 1B, 2A, 2B, 2C, 3A, 3B and 3C to two (2) new transfer stations designated as B1 & B2 each with a maximum capacity of 200 tons per hour. The particulate emissions from each transfer station silo will be controlled by bin-vent filters to 0.01 gr/dscf.
 - (2) one (1) pneumatic fly ash transfer system conveying ash from the two (2) transfer station silos to two (2) new fixation silos designated as B3 & B4 each with a maximum capacity of 200 tons per hour. The particulate emissions from each fixation silo will be controlled by bin-vent filters to 0.01 gr/dscf.
 - (3) one (1) pneumatic fly ash transfer system equipped enclosed screw conveyers from the two (2) fixation silos to a new Fixation Building with particulate emissions controlled by a dust collector C1 (with a spare dust collector C2).
 - (4) Loading of fly ash into trucks for transport to the landfill from fixation silos B3 & B4 using wet unloaders.
 - (5) Truck loading of two (2) new lime silos designated B5 & B6 for use in the Fixation Building, each with bin-vent filters controlling particulate matter emissions to 0.01 gr/dscf.
 - (6) One (1) fly ash day bin designated B7 with a maximum capacity of 200 tons per hour with particulate matter emissions controlled by a bin-vent filter to 0.01 gr/dscf.

(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.10.1 PSD Minor Limits and Particulate Emission Limitation for Manufacturing Processes [326 IAC 2-2] [326 IAC 6-3-2]

In order to make the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) not applicable, the Permittee shall comply with the following for the Dry fly ash handling system:

- (A) The total hours of operation for the Exhauster 3A, Exhauster 3B, Exhauster 3C (spare) Exhauster 1A, Exhauster 1B, Exhauster 2A, Exhauster 2B, Spare Exhauster, (B3) Remote Fly Ash Silo A Bin Vent Filter and (B4) Remote Fly Ash Silo B Bin Vent Filter shall be less than 4745 hours each per twelve (12) consecutive month period, with compliance determined at the end of each month.
 - (a) PM and PM10 emissions from the Exhauster 3A, Exhauster 3B and Exhauster 3C (spare) shall not exceed 0.188 pounds per hour, each.
 - (b) PM and PM10 emissions from the Exhauster 1A, Exhauster 1B, Exhauster 2A, Exhauster 2B and Spare Exhauster shall not exceed 0.28 pounds per hour, each.

- (c) PM and PM10 emissions from (B3) Remote Fly Ash Silo A Bin Vent Filter and (B4) Remote Fly Ash Silo B Bin Vent Filter shall not exceed 0.65 pounds per hour, each.
 - (d) Only two out of the three exhausters, identified as Exhauster 3A, Exhauster 3B and Exhauster 3C (spare) shall operate at any time.
 - (e) Only four out of the five exhausters, identified as Exhauster 1A, Exhauster 1B, Exhauster 2A, Exhauster 2B and Spare Exhauster shall operate at any time.
- (B) The total hours of operation for the U1 Bin Vent Filter and U2 Bin Vent Filter shall be less than 5840 hours each per twelve (12) consecutive month period, with compliance determined at the end of each month.
- (a) PM and PM10 emissions from the U1 Bin Vent Filter and U2 Bin Vent Filter shall not exceed 0.13 pounds per hour, each.
- (C) The total hours of operation for the Lime Silo A Bin Vent Filter and Lime Silo B Bin Vent Filter shall be less than 2920 hours each per twelve (12) consecutive month period, with compliance determined at the end of each month.
- (a) PM and PM10 emissions from the Lime Silo A Bin Vent Filter and Lime Silo B Bin Vent Filter shall not exceed 0.085 pounds per hour, each.
- (D) The total hours of operation for the Fly Ash Day Bin vent Filter shall be less than 8760 hours per twelve (12) consecutive month period, with compliance determined at the end of each month.
- (a) PM and PM10 emissions from the Fly Ash Day Bin vent Filter shall not exceed 0.12 pounds per hour, each.
- (E) PM and PM10 emissions from the Dust Collector A shall not exceed 0.386 pounds per hour, each.
- (a) Only one out of the two dust collectors, identified as Dust Collector A and Dust Collector B (Spare) shall operate at any time.

Compliance with these limits will limit the potential to emit of PM and PM₁₀ emissions from the dry fly ash handling system to less than 25 and 15 per year, respectively and render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2011 modification.

This condition will also satisfy for 326 IAC 6-3-2 for the emission units being constructed in 2011.

D.10.2 Emission Offset [326 IAC 2-3]

In order to make the requirements of 326 IAC 23 (Emission Offset) not applicable, the Permittee shall comply with the following for the Dry fly ash handling system:

- (A) The total hours of operation for the Exhauster 3A, Exhauster 3B, Exhauster 3C (spare) Exhauster 1A, Exhauster 1B, Exhauster 2A, Exhauster 2B, Spare Exhauster, (B3) Remote Fly Ash Silo A Bin Vent Filter and (B4) Remote Fly Ash Silo B Bin Vent Filter shall be less than 4745 hours each per twelve (12) consecutive month period, with compliance determined at the end of each month.
- (a) PM and PM10 emissions from the Exhauster 3A, Exhauster 3B and Exhauster 3C (spare) shall not exceed 0.188 pounds per hour, each.

- (b) PM and PM10 emissions from the Exhauster 1A, Exhauster 1B, Exhauster 2A, Exhauster 2B and Spare Exhauster shall not exceed 0.28 pounds per hour, each.
 - (c) PM and PM10 emissions from (B3) Remote Fly Ash Silo A Bin Vent Filter and (B4) Remote Fly Ash Silo B Bin Vent Filter shall not exceed 0.65 pounds per hour, each.
 - (d) Only two out of the three exhausters, identified as Exhauster 3A, Exhauster 3B and Exhauster 3C (spare) shall operate at any time.
 - (e) Only four out of the five exhausters, identified as Exhauster 1A, Exhauster 1B, Exhauster 2A, Exhauster 2B and Spare Exhauster shall operate at any time.
- (B) The total hours of operation for the U1 Bin Vent Filter and U2 Bin Vent Filter shall be less than 5840 hours each per twelve (12) consecutive month period, with compliance determined at the end of each month.
- (a) PM and PM10 emissions from the U1 Bin Vent Filter and U2 Bin Vent Filter shall not exceed 0.13 pounds per hour, each.
- (C) The total hours of operation for the Lime Silo A Bin Vent Filter and Lime Silo B Bin Vent Filter shall be less than 2920 hours each hours per twelve (12) consecutive month period, with compliance determined at the end of each month.
- (a) PM2.5 emissions from the Lime Silo A Bin Vent Filter and Lime Silo B Bin Vent Filter shall not exceed 0.085 pounds per hour, each.
- (D) The total hours of operation for the Fly Ash Day Bin vent Filter shall be less than 8760 hours per twelve (12) consecutive month period, with compliance determined at the end of each month.
- (a) PM2.5 emissions from the Fly Ash Day Bin vent Filter shall not exceed 0.12 pounds per hour.
- (E) PM2.5 emissions from the Dust Collector A shall not exceed 0.386 pounds per hour.
- (a) Only one out of the two dust collectors, identified as Dust Collector A and Dust Collector B (Spare) shall operate at any time.

Compliance with these limits will limit the potential to emit of PM_{2.5} emissions from the dry fly ash handling system to less than 10 tons per year and render the requirements of 326 IAC 2-1.1-5 (Nonattainment NSR) not applicable to the 2011 modification.

D.10.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

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

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

D.10.4 Particulate Control [326 IAC 2-7-6(6)]

- (a) In order to comply with Conditions D.10.1 and D.10.2, the filters separators, bin vent filter and the dust collectors for particulate control shall be in operation and control emissions from these emission units at all times that these emission units are in operation.

- (b) In the event that bag failure is observed in a multi-compartment baghouse, if operations will continue for ten (10) days or more after the failure is observed before the failed units will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed units will be repaired or replaced. The notification shall also include the status of the applicable compliance monitoring parameters with respect to normal, and the results of any response actions taken up to the time of notification.

D.10.5 Testing requirements [326 IAC 2-7-6(1),(6)][326 IAC 2-1.1-11]

- (a) In order to demonstrate compliance with PM, PM10 and PM2.5 limitations in Conditions D.10.1(A)(a), (b) and D.10.2 A (a) and (b), the Permittee shall perform stack test on two (2) of the eight (8) separator/exhausters utilizing methods as approved by the Commissioner at least once every 5 years from the date of the most recent valid compliance demonstration. The separator/exhauster tested shall be the unit in which the longest amount of time has elapsed since its previous test. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.
- (b) In order to demonstrate compliance with PM, PM10 and PM2.5 limitations in Conditions D.10.1(E) and D.11.2 (E), the Permittee shall perform stack test on one (1) of the two (2) fixation building dust collectors utilizing methods as approved by the Commissioner at least once every 5 years from the date of the most recent valid compliance demonstration. 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.

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

D.10.6 Visible Emissions Notations [40 CFR 64]

- (a) Visible emission notations of the truck loading stations shall be performed at least once per day during normal daylight operations when ash is being loaded and unloaded. A trained employee shall record whether any emissions are normal or abnormal.
- (b) Visible emission notations of the separator/exhausters shall be performed at least once per week during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.
- (c) Visible emission notations of the silo bin vent filters shall be performed at least once per week during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.
- (d) Visible emission notations of the fixation building dust collector exhaust shall be performed at least once per week during normal daylight operations when the pin-paddle mixers are operating. A trained employee shall record whether emissions are normal or abnormal.
- (e) Visible emissions of the landfill area shall be performed at least once per day during normal daylight hours. A trained employee shall record whether emissions are normal or abnormal.

- (f) If visible emissions are observed crossing the property line or boundaries of the property, right-of-way, or easement on which the source is located, the Permittee shall take reasonable response steps. Failure to take response steps, shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.
- (g) 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.
- (h) 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.
- (i) 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.
- (j) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

D.10.7 Reserved

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

D.10.8 Record Keeping Requirements [40 CFR 64]

- (a) To document the compliance status with Conditions D.10.1 (A), (B), (C), (D) and D.10.2 (A), (B), (C), and (D), the Permittee shall maintain monthly records of hours of operation of the Dry fly ash handling system.
- (b) To document the compliance status with Condition D.10.6 (a) and (e) - Visible Emission Notation, the Permittee shall maintain records of visible emission notations of truck loading stations and the landfill area once per day. 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) To document the compliance status with Condition D.10.6 (b), (c) and (d) - Visible Emission Notation, the Permittee shall maintain records of visible emission notations of separator/exhausters, silo bin vent filters and fixation building dust collector exhaust once per week. 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).
- (e) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.10.9 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.10.1 (A), (B), (C), (D) and D.10.2 (A), (B), (C) and (D) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (a) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring; buffing; polishing; abrasive blasting; pneumatic conveying; and woodworking operations.[326 IAC 6-3-2]
- (b) Conveyors as follows: [326 IAC 6-3]
- (1) Covered conveyor for coal or coke conveying of less than or equal to 360 tons per day;
 - (2) Covered conveyors for limestone conveying of less than or equal to 7,200 tons per day for sources other than mineral processing plants constructed after August 31, 1983;
 - (3) Underground conveyors.
- (c) Coal bunker and coal scale exhausts and associated dust collector vents. [326 IAC 6-3]

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

Pursuant to 326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes), the allowable particulate emission rate from the grinding and machining facilities shall not exceed 0.551 pounds per hour (lbs/hr) based on the following equation:

Interpolation of the data for the process weight rate up to 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

D.11.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the Preventive Maintenance Plan required by this condition.

SECTION E.1 ACID RAIN PROGRAM CONDITIONS

ORIS Code: 6113

Emissions Unit Description:

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)
[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)
[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with a flue gas conditioning system and an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)
[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 4.

Boiler No. 4 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)
[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 5.

Boiler No. 5 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

(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)]

E.1.1. Statutory and Regulatory Authorities

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

E.1.2. Standard Permit Requirements [326 IAC 21]

- (a) The designated representative has submitted a complete acid rain permit application in accordance with 40 CFR 72.30.
- (b) The Permittee shall operate Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5 in compliance with this permit.

E.1.3. Monitoring Requirements [326 IAC 21]

- (a) The Permittee and, to the extent applicable, the designated representative of Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5 shall comply with the monitoring requirements as provided in 40 CFR 75 and 76.
- (b) The emissions measurements recorded and reported in accordance with 40 CFR 75 and 76 shall be used to determine compliance by Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5 with the acid rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
- (c) The requirements of 40 CFR 75 and 76 shall not affect the responsibility of the Permittee to monitor emissions of other pollutants or other emissions characteristics at Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5 under other applicable requirements of the Clean Air Act and other provisions of the operating permit for the source.

E.1.4. Sulfur Dioxide Requirements [326 IAC 21]

- (a) The Permittee shall:
 - (1) Hold allowances, as of the allowance transfer deadline (as defined in 40 CFR 72.2), in the compliance subaccount of Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5, after deductions under 40 CFR 73.34(c), not less than the total annual emissions of sulfur dioxide for the previous calendar year from Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5; and,
 - (2) Comply with the applicable acid rain emissions limitations for sulfur dioxide.
- (b) Each ton of sulfur dioxide emitted in excess of the acid rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Clean Air Act.
- (c) Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5 shall be subject to the requirements under paragraph 4(a) of the sulfur dioxide requirements as follows:
 - (1) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or,

- (2) Starting on the latter of January 1, 2000, or the deadline for monitor certification under 40 CFR 75, an affected unit under 40 CFR 72.6(a)(3).
- (d) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
- (e) An allowance shall not be deducted in order to comply with the requirements under paragraph 4(a) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
- (f) An allowance allocated by the U.S. EPA under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the acid rain permit application, the acid rain permit, the acid rain portion of an operating permit, or the written exemption under 40 CFR 72.7 and 72.8 and 326 IAC 21, and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
- (g) An allowance allocated by U.S. EPA under the Acid Rain Program does not constitute a property right.
- (h) No permit revision may be required for increases in emissions that are authorized by allowances acquired pursuant to the Acid Rain Program, provided that the increases do not require a permit revision under any other applicable requirement. [326 IAC 2-7-5(4)(A)]
- (i) No limit shall be placed on the number of allowances held by the Permittee. The Permittee may not, however, use allowances as a defense to noncompliance with any applicable requirement other than the requirements of the Acid Rain Program. [326 IAC 2-7-5(4)(B)]

E.1.5. Nitrogen Oxides Requirements [326 IAC 21]

- (a) The Permittee shall comply with the applicable acid rain emissions limitation for nitrogen oxides (NOx) for Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5.
- (b) NOx Emission Averaging Plan for Unit 1:
 - (1) Pursuant to 40 CFR 76.11, IDEM, OAQ approves a NOx emission averaging plan for Unit 1, effective from calendar year 2007 through 2011. Under the plan the NOx emissions from Unit 1 shall not exceed the alternative contemporaneous annual emission limitation (ACEL) of 0.29 lb/MMBtu. In addition, Unit 1 shall not have an annual heat input less than 40,679,344 MMBtu.
 - (2) Under the plan, the actual Btu-weighted annual average NOx emission rate for all the units in the plan shall be less than or equal to the Btu-weighted annual average NOx emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then Unit 1 shall be deemed to be in compliance for that year with its annual ACEL and annual heat input limit.
- (c) NOx Emission Averaging Plan for Unit 2:
 - (1) Pursuant to 40 CFR 76.11, IDEM, OAQ approves a NOx emission averaging plan for Unit 2, effective from calendar year 2007 through 2011. Under the plan

the NOx emissions from Unit 2 shall not exceed the ACEL of 0.29 lb/MMBtu. In addition, Unit 2 shall not have an annual heat input less than 35,784,543 MMBtu.

- (2) Under the plan, the actual Btu-weighted annual average NOx emission rate for all the units in the plan shall be less than or equal to the Btu-weighted annual average NOx emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then Unit 2 shall be deemed to be in compliance for that year with its annual ACEL and annual heat input limit.
- (d) NOx Emission Averaging Plan for Unit 3:
- (1) Pursuant to 40 CFR 76.11, IDEM, OAQ approves a NOx emission averaging plan for Unit 3, effective from calendar year 2007 through 2011. Under the plan the NOx emissions from Unit 3 shall not exceed the ACEL of 0.30 lb/MMBtu. In addition, Unit 3 shall not have an annual heat input less than 45,485,728 MMBtu.
 - (2) Under the plan, the actual Btu-weighted annual average NOx emission rate for all the units in the plan shall be less than or equal to the Btu-weighted annual average NOx emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then Unit 3 shall be deemed to be in compliance for that year with its annual ACEL and annual heat input limit.
- (e) NOx Emission Averaging Plan for Unit 4:
- (1) Pursuant to 40 CFR 76.11, IDEM, OAQ approves a NOx emission averaging plan for Unit 4, effective from calendar year 2007 through 2011. Under the plan the NOx emissions from Unit 4 shall not exceed the ACEL of 0.29 lb/MMBtu. In addition, Unit 4 shall not have an annual heat input less than 53,603,321 MMBtu.
 - (2) Under the plan, the actual Btu-weighted annual average NOx emission rate for all the units in the plan shall be less than or equal to the Btu-weighted annual average NOx emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then Unit 4 shall be deemed to be in compliance for that year with its annual ACEL and annual heat input limit.
- (f) NOx Emission Averaging Plan for Unit 5:
- (1) Pursuant to 40 CFR 76.11, IDEM, OAQ approves a NOx emission averaging plan for Unit 5, effective from calendar year 2007 through 2011. Under the plan the NOx emissions from Unit 5 shall not exceed the ACEL of 0.30 lb/MMBtu. In addition, Unit 5 shall not have an annual heat input less than 47,798,920 MMBtu.

- (2) Under the plan, the actual Btu-weighted annual average NOx emission rate for all the units in the plan shall be less than or equal to the Btu-weighted annual average NOx emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then Unit 5 shall be deemed to be in compliance for that year with its annual ACEL and annual heat input limit.
- (g) In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only when the Kentucky Department of Environmental Protection, Division of Air Quality; North Carolina Department of Environmental and Natural Resources, Division of Air Quality; and South Carolina Department of Health and Environmental Control, Bureau of Air Quality have also approved this averaging plan.
- (h) In addition to the described NOx compliance plan, the units shall comply with all other applicable requirements of 40 CFR 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.

E.1.6. Excess Emissions Requirements [40 CFR 77] [326 IAC 21]

- (a) If Unit 1, 2, 3, 4, or 5 has excess emissions of sulfur dioxide in any calendar year, the designated representative shall submit a proposed offset plan to U.S. EPA and IDEM, OAQ as required under 40 CFR 77 and 326 IAC 21.

- (b) The designated representative shall submit required information to:

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

and

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

- (c) If Unit 1, 2, 3, 4, or 5 has excess emissions, as defined in 40 CFR 72.2, in any calendar year the Permittee shall:
- (1) Pay to U.S. EPA without demand the penalty required, and pay to U.S. EPA upon demand the interest on that penalty, as required by 40 CFR 77 and 326 IAC 21; and,
- (2) Comply with the terms of an approved sulfur dioxide offset plan, as required by 40 CFR 77 and 326 IAC 21.

E.1.7. Record Keeping and Reporting Requirements [326 IAC 21]

- (a) Unless otherwise provided, the Permittee shall keep on site each of the following documents for a period of 5 years, as required by 40 CFR 72.9(f), from the date the document is created. This period may be extended for cause, at any time

prior to the end of the 5 years, in writing by U.S. EPA or IDEM, OAQ:

- (1) The certificate of representation for the designated representative of Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5 and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5 year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
 - (2) All emissions monitoring information collected in accordance with 40 CFR 75 shall be retained on site for 3 years;
 - (3) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
 - (4) Copies of all documents used to complete an acid rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
- (b) The designated representative of Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5 shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 72.90, Subpart I, 40 CFR 75, and 326 IAC 21. The required information is to be submitted to the appropriate authority(ies) as specified in 40 CFR 72.90, Subpart I, and 40 CFR 75.

E.1.8. Submissions [326 IAC 21]

- (a) The designated representative of Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5 shall submit a certificate of representation, and any superseding certificate of representation, to U.S. EPA and IDEM, OAQ in accordance with 40 CFR 72 and 326 IAC 21.
- (b) The designated representative shall submit required information to:

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

and

U.S. Environmental Protection Agency
 Clean Air Markets Division
 1200 Pennsylvania Avenue, NW
 Mail Code (6204N)
 Washington, DC 20460
- (c) Each such submission under the Acid Rain Program shall be submitted, signed and certified by the designated representative for all sources on behalf of which the submission is made.
- (d) In each submission under the Acid Rain Program, the designated representative shall certify, by his or her signature, the following statements which shall be included verbatim in the submission:

- (1) "I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made."; and
 - (2) "I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."
- (e) The designated representative of Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5 shall notify the Permittee:
- (1) By the date of submission, of any Acid Rain Program submissions by the designated representative;
 - (2) Within 10 business days of receipt of any written determination by U.S. EPA or IDEM, OAQ; and,
 - (3) Provided that the submission or determination covers Unit 1, 2, 3, 4, or 5.
- (f) The designated representative of Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5 shall provide the Permittee a copy of any submission or determination under paragraph 8(e), unless the Permittee expressly waives the right to receive a copy.

E.1.9. Severability [326 IAC 21]

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

E.1.10. Liability [326 IAC 21]

- (a) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, an acid rain permit, an acid rain portion of an operation permit, or a written exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement by U.S. EPA pursuant to Section 113(c) of the Clean Air Act and shall be subject to enforcement by IDEM pursuant to 326 IAC 21 and IC 13-30-3.
- (b) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to Section 113(c) of the Clean Air Act, 18 U.S.C. 1001 and IDEM pursuant to 326 IAC 21 and IC 13-30-6-2.
- (c) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
- (d) Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5 shall meet the requirements of the Acid Rain Program.
- (e) Any provision of the Acid Rain Program that applies to Unit 1, 2, 3, 4, or 5, including a provision applicable to the designated representative of Unit 1, 2, 3, 4, or 5 shall also apply to the Permittee.

- (f) Any provision of the Acid Rain Program that applies to Unit 1, 2, 3, 4, or 5, including a provision applicable to the designated representative, shall also apply to the Permittee. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NOx averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR 75, including 40 CFR 75.16, 75.17, and 75.18, the Permittee and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
- (g) Each violation of a provision of 40 CFR 72, 73, 75, 76, 77, and 78 by Unit 1, 2, 3, 4, or 5, or by the Permittee or designated representative shall be a separate violation of the Clean Air Act.

E.1.11. Effect on Other Authorities [326 IAC 21]

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

- (a) Except as expressly provided in Title IV of the Clean Air Act (42 USC 7651 to 7651(o)), exempting or excluding the Permittee and, to the extent applicable, the designated representative of Unit 1, 2, 3, 4, or 5 from compliance with any other provision of the Clean Air Act, including the provisions of Title I of the Clean Air Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
- (b) Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Clean Air Act;
- (c) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law;
- (d) Modifying the Federal Power Act (16 USC 791(a) et seq.) or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; and
- (e) Interfering with or impairing any program for competitive bidding for power supply in a state in which such a program is established.

SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 5.

Boiler No. 5 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

(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 [326 IAC 12] [40 CFR Part 60, Subpart D]

E.2.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the emission units identified as Boiler No. 5, except as otherwise specified in 40 CFR Part 60, Subpart D.

E.2.2 New Source Performance Standards of Performance for Fossil-Fuel-Fired Steam Generators [40 CFR Part 60, Subpart D] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart D, the Permittee shall comply with the provisions of New Source Performance Standards of Performance for Fossil-Fuel-Fired Steam Generators, which are incorporated by reference as 326 IAC 12, (included as Attachment A of this permit), for the above emission unit as specified as follows:

- (1) 40 CFR 60.40 (a)(1), (c)
- (2) 40 CFR 60.41 (a)
- (3) 40 CFR 60.42 (a)(1), (a)(2)
- (4) 40 CFR 60.43 (a)(2)
- (5) 40 CFR 60.44 (a)(3)
- (6) 40 CFR 60.45 (a), (c), (e), (g)
- (7) 40 CFR 60.46

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (1) A limestone processing system, consisting of the following equipment:
 - (A) One (1) unloading station for trucks or railcar, with a drop point to a hopper identified as LSDP-1 with a nominal throughput of 2,500 tons of limestone per hour, with the drop point controlled by a partial enclosure, and exhausting to the ambient air.
 - (B) Two (2) enclosed hoppers, each with a drop point to conveyors identified as LSDP-2 and LSDP-5 with a nominal throughput of 200 tons of limestone per hour, with each drop point enclosed.
 - (C) One (1) storage pile, with a nominal storage capacity of 50,000 tons, with a drop point to a hopper identified as LSDP-4, with the drop point enclosed and exhausting to the ambient air.
 - (D) An enclosed conveyor system, with four (4) drop points identified as LSDP-3 and LSDP-8 through LSDP-10, with each drop point enclosed.
 - (E) One (1) enclosed hammermill, with a drop point to a conveyor identified as LSDP-6, with the drop point enclosed.
 - (F) Two (2) day bins for temporary storage of limestone, with a combined storage capacity of 13,000 tons, with dust from loading the bins controlled by bin vent filters, and exhausting to the ambient air.
- (2) Limestone Handling (TP-1 to TP-5, TP-10 to TP-17, F-6 and F-9), with maximum capacity of 2,500 tons per hour:
 - (A) Transfer of limestone from railcar or truck to the limestone hopper, with fogging type dust suppression as particulate control.
 - (B) Enclosed transfer of limestone from unloading hoppers to belt feeders.
 - (C) Enclosed transfer of limestone from belt feeders to conveyors.
 - (D) Telescoping chute transfer of limestone from conveyor to lime storage stockout pile.
 - (E) Enclosed transfer of limestone from the reclaim hoppers to belt feeders, with fogging type dust suppression as particulate control.
 - (F) Enclosed transfer of limestone from conveyor to conveyor, with fogging type dust suppression as particulate control.
 - (G) Transfer of limestone from conveyor to day bin, with surge-bin filter as particulate control.
 - (H) Enclosed transfer of limestone from conveyor fixed hopper to conveyor with fogging type dust suppression as particulate control.
 - (I) Transfer of limestone from conveyor fixed tripper to day bin, with surge-bin filter as particulate control.

- (J) Limestone storage piles, with watering type dust suppression as fugitive dust control.

(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 [326 IAC 12] [40 CFR Part 60, Subpart OOO]

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

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

E.3.2 New Source Performance Standards for Standard of Performance for Non-metallic Mineral Processing Plants [40 CFR Part 60, Subpart OOO] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart OOO, the Permittee shall comply with the provisions of New Source Performance Standards for Standard of Performance for Non-metallic Mineral Processing Plants, which are incorporated by reference as 326 IAC 12, (included as Attachment B of this permit), for the above emission units as specified as follows:

- (1) 40 CFR 60.670(a)(1), (d)(1-3), (e-f)
- (2) 40 CFR 60.671
- (3) 40 CFR 60.672(a-b), (d-f), (e)(1-2), (f)
- (4) 40 CFR 60.673
- (5) 40 CFR 60.674(a)(1), (a)(2)
- (6) 40 CFR 60.675(b)(1), (b)(2), (c)(1)(i-ii); (c)(2)(i-ii); (c)(3), (d)(2)
- (7) 40 CFR 60.675(e)(1)(i-ii); (e)(2)(i-iii); (e)(3), (e)(4), (g)
- (8) 40 CFR 60.676(a)(1), (a)(3), (a)(4), (f), (j), (k)
- (9) 40 CFR 60, Subpart OOO, Table 1
- (10) 40 CFR 60, Subpart OOO, Table 2
- (11) 40 CFR 60, Subpart OOO, Table 3

SECTION E.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (e) One (1) emergency firewater pump engine, rated at 575 horsepower (HP) and identified as Pump #2, installed in 2007 and permitted in 2013. [Under 40 CFR 60, Subpart IIII, the firewater pump engine is considered an existing affected source.]

(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 [326 IAC 12] [40 CFR 60, Subpart IIII]

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

The provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the emergency diesel generators and the firewater pump diesel engines described in this section except when otherwise specified in 40 CFR Part 60, Subpart IIII.

E.4.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [326 IAC 12][40 CFR Part 60, Subpart IIII]

The Permittee who owns and operates stationary compression ignition (CI) internal combustion engines (ICE) shall comply with the following provisions of 40 CFR Part 60, Subpart IIII, included as Attachment D of this permit. The source is subject to the following portions of Subpart IIII:

- (1) 40 CFR 60.4200(a);
- (2) 40 CFR 60.4205(b);
- (3) 40 CFR 60.4205(c);
- (4) 40 CFR 60.4206;
- (5) 40 CFR 60.4207(a);
- (6) 40 CFR 60.4207(b);
- (7) 40 CFR 60.4208(a);
- (8) 40 CFR 60.4208(b);
- (9) 40 CFR 60.4208(g);
- (10) 40 CFR 60.4209(a);
- (11) 40 CFR 60.4211(a);
- (12) 40 CFR 60.4211(c);
- (13) 40 CFR 60.4211(e);
- (14) 40 CFR 60.4212(a);
- (15) 40 CFR 60.4212(b);
- (16) 40 CFR 60.4212(c);
- (17) 40 CFR 60.4214(b);
- (18) 40 CFR 60.4218;
- (19) 40 CFR 60.4219;
- (20) Table 4 to Subpart IIII of Part 60 - Emission Standard for Stationary Fire Pump Engines;
- (21) Table 5 to Subpart IIII of Part 60 - Labeling and Recordkeeping Requirements for New Stationary Emergency Engines;
- (22) Table 8 to Subpart IIII of Part 60 - Applicability of General Provisions to Subpart IIII.

SECTION E.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (d) One (1) emergency firewater pump engine, rated at 500 horsepower (HP) and identified as Pump #1, installed in 1995 and permitted in 2013.[Under 40 CFR 63, Subpart ZZZZ, the firewater pump engine is considered an existing affected source.]

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

National Emissions Standard for Hazardous Air Pollutants [326 IAC 20] [40 CFR 63, Subpart ZZZZ]

- E.5.1 General Provisions Relating to National Emissions Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [326 IAC 20-1][40 CFR Part 63, Subpart A]

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

- E.5.2 National Emissions Standard for Hazardous Air Pollutants for stationary Reciprocating Internal Combustion Engines [40 CFR Part 63, Subpart ZZZZ][326 IAC 20-82-1]

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

- (1) 40 CFR 63.6585(a), (b)
- (2) 40 CFR 63.6590(a)(2)(i)
- (3) 40 CFR 63.6595(a)(3), (c)
- (4) 40 CFR 63.6600(d)
- (5) 40 CFR 63.6605
- (6) 40 CFR 63.6610
- (7) 40 CFR 63.6625(h),(i)
- (8) 40 CFR 63.6630
- (9) 40 CFR 63.6635
- (10) 40 CFR 63.6640
- (11) 40 CFR 63.6645(a)(3)
- (12) 40 CFR 63.6645(g)
- (13) 40 CFR 63.6650
- (14) 40 CFR 63.6655
- (15) 40 CFR 63.6660
- (16) 40 CFR 63.6665
- (17) 40 CFR 63, Table 1a, 1b
- (18) 40 CFR 63, Table 2a, 2b, 2c, 2d
- (19) 40 CFR 63, Table 6
- (20) 40 CFR 63, Table 7

SECTION E.6 EMISSIONS UNIT OPERATION CONDITIONS**Emissions Unit Description:**

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), and with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 4.

Boiler No. 4 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x) sulfur dioxide (SO₂) and particulate matter (PM)

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 5.

Boiler No. 5 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

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

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

E.6.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

- (a) Pursuant to 40 CFR 63.9065, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated by reference as 326 IAC 20-1-1, for the above listed emission unit, except as otherwise specified in 40 CFR Part 63, Subpart UUUUU, in accordance with the schedule in 40 CFR Part 63, Subpart UUUUU.
- (b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
 Compliance and Enforcement Branch, Office of Air Quality
 100 North Senate Avenue
 MC 61-53 IGCN 1003
 Indianapolis, IN 46204-22551

E.6.2 Coal- And Oil-Fired Electric Utility Steam Generating Units NESHAP [40 CFR Part 63, Subpart UUUUU][326 IAC 20-89]

Pursuant to 40 CFR 63, Subpart UUUUU the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart UUUUU as applicable, which are incorporated by reference as 326 IAC 20-89 (included as Attachment F to this permit), for the above emission unit as specified as follows:

- (1) 40 CFR 63.9981
- (2) 40 CFR 63.9982(a)(1), (d)
- (3) 40 CFR 63.9984(b), (c), (f)
- (4) 40 CFR 63.9990(a)(1), (a)(2)
- (5) 40 CFR 63.9991(a)(1), (a)(2), (b), (c)(1), (c)(2)
- (6) 40 CFR 63.10000(a), (b), (c)(1)(iv); (v), (vi)(B), (d)(1), (d)(2)(i), (d)(2)(ii), (d)(3), (d)(4), (d)(5)(i-vii); (e), (l)
- (7) 40 CFR 63.10005(a), (a)(1), (a)(2)(i-iii); (b)(1-5); (d)(1), (d)(2)(i-iii); (d)(3), (e), (h)(1)(i)-(ii)(A-B); (h)(2)(i-ii); (h)(3)(i)(A-D); (h)(3)(ii); (h)(3)(iii)(A-B); (h)(3)(iii)(C)(1-5); (j), (k)
- (8) 40 CFR 63.10006(b)(1-2); (c), (d), (f), (i), (j)
- (9) 40 CFR 63.10007(a)(1), (a)(2), (b), (d), (e)(1), (e)(2), (f)(1)(ii) and (2); (g)
- (10) 40 CFR 63.10009(a), (b)(1), (b)(2), (d), (e), (f)(1), (g)(1), (h- k), (n)
- (11) 40 CFR 63.10010(a)(2)(ii); (b-e), (a)(4), (c-e), (f)(1-4); (g), (h)(1-7); (i)(1-5); (j)(1-4); (l)(1-5)
- (12) 40 CFR 63.10011(a-g)
- (13) 40 CFR 63.10020(a-d), (e)(1) – (3)(i)(A- D)
- (14) 40 CFR 63.10021(a-c); (d)(1-2); (e-i)
- (15) 40 CFR 63.10022
- (16) 40 CFR 63.10030(a), (b), (d), (e)
- (17) 40 CFR 63.10031(a-g)

- (18) 40 CFR 63.10032(a), (b), (d)(1)
- (19) 40 CFR 63.10033(a-c)
- (20) 40 CFR 63.10040
- (21) 40 CFR 63.10041(a-b)
- (22) 40 CFR 63.10042
- (23) 40 CFR 63 Appendix A to Subpart UUUUU
- (24) 40 CFR 63, Subpart UUUUU, Table 2, Subcategory 1
- (25) 40 CFR 63, Subpart UUUUU, Table 3, Subcategory 1
- (26) 40 CFR 63, Subpart UUUUU, Table 5, Subcategories 1-5
- (27) 40 CFR 63, Subpart UUUUU, Table 7, Subcategory 1
- (28) 40 CFR 63, Subpart UUUUU, Table 8, Subcategory 1
- (29) 40 CFR 63, Subpart UUUUU, Table 9

SECTION F.1

SO₃ MITIGATION PLAN**Emissions Unit Description:**

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) [This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)
[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) [This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 4.

Boiler No. 4 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)
[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction

(SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 5.

Boiler No. 5 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)
 [This facility is an affected source under 40 CFR 63, Subpart UUUUU]

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

F.1 SO₃ Mitigation System [326 IAC 2-2.3]

- (a) Pursuant to 326 IAC 2-2.3, the Permittee shall operate the SO₃ Mitigation System utilizing Sodium Bisulfite (SBS) or other mitigation reagents whenever a Selective Catalytic Reduction System (SCR) is in operation in conjunction with a Flue Gas Desulfurization System (FGD), except:
- (1) During SCR startups; or
 - (2) If the SO₃ mitigation system shuts down due to events beyond the reasonable control of the Permittee or there is need for emergency maintenance repairs.
- (b) If events described in Condition F.1(a)(1) and F.1(a)(2) occur, the Permittee cannot start or restart the SO₃ mitigation system within one (1) hour.

The station personnel shall notify IDEM in accordance with the emergency notification provisions of 326 IAC 2-7-16(b) and if there is potential for plume touchdown in the opinion of station personnel and/or IDEM, the respective SCR shall be taken out of service.

F.2 Reserved

F.3 Minimum Injection Rate

- (a) The Permittee shall operate the SO₃ mitigation system when both the SCR and FGD are in service at a minimum injection rate of 0.9 molar ratio, including during any periods when mitigating a single duct or gas stream if demonstrated to be SCR neutral.
- (b) At all times when both the SCR and FGD are in service, except as described in Condition F.1(a)(1) and F.1(a)(2), a minimum of at least one (1) duct shall be treated for SO₃ mitigation.
- (c) Any change in the established minimum injection rate, the Permittee shall report such change with supporting information.

F.4 Plume Touchdown

In the event that a plume touchdown is observed, IDEM and the appropriate local authorities shall be immediately notified of this event and the respective SCR(s) causing such plume touchdown shall be removed from service.

The SCR shall remain out of service until the conditions or cause resulting in the plume touchdown subside or are resolved.

SECTION G**TR NO_x Annual Trading Program, TR NO_x Ozone Season Trading Program, and TR SO₂ Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.506), (40 CFR 97.606)**

ORIS Code: 6137

Transport Rule (TR):

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) [This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 4.

Boiler No. 4 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 4.

Boiler No. 5 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

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

G.1 Designated representative requirements

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

- (1) 40 CFR 97.413 through 97.418;
- (2) 40 CFR 97.513 through 97.518; and
- (3) 40 CFR 97.613 through 97.618.

G.2 Emissions monitoring, reporting, and recordkeeping requirements

- (1) The owners and operators, and the designated representative, of each TR NO_x Annual source, TR NO_x Ozone Season source, and TR SO₂ Group 1 source, and each TR NO_x Annual unit at the source, TR NO_x 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).
- (2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of TR NO_x Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the TR NO_x Annual emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 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.
- (3) The emissions data determined in accordance with 40 CFR 97.530 through 97.535 shall be used to calculate allocations of TR NO_x Ozone Season allowances under 40 CFR 97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NO_x Ozone Season emissions limitation and assurance provisions under paragraph (d) 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.

- (4) 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 paragraph (e) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

G.3 NOX annual emissions requirements

- (1) TR NO_x Annual emissions limitation.
- (i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_x Annual source and each TR NO_x Annual unit at the source shall hold, in the source's compliance account, TR NO_x 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 NO_x emissions for such control period from all TR NO_x Annual units at the source.
 - (ii). If total NO_x emissions during a control period in a given year from the TR NO_x Annual units at a TR NO_x Annual source are in excess of the TR NO_x Annual emissions limitation set forth in paragraph (c)(1)(i) above, then:
 - (A). The owners and operators of the source and each TR NO_x Annual unit at the source shall hold the TR NO_x Annual allowances required for deduction under 40 CFR 97.424(d); and
 - (B). The owners and operators of the source and each TR NO_x Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.
- (2) TR NO_x Annual assurance provisions.
- (i). If total NO_x emissions during a control period in a given year from all TR NO_x Annual units at TR NO_x 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 NO_x emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_x 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 NO_x emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such

- sources and units in the state for such control period, by which each common designated representative's share of such NO_x emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_x emissions from all TR NO_x Annual units at TR NO_x Annual sources in the state for such control period exceed the state assurance level.
- (ii). The owners and operators shall hold the TR NO_x Annual allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.
 - (iii). Total NO_x emissions from all TR NO_x Annual units at TR NO_x Annual sources in the State during a control period in a given year exceed the state assurance level if such total NO_x emissions exceed the sum, for such control period, of the state NO_x Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).
 - (iv). It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NO_x emissions from all TR NO_x Annual units at TR NO_x Annual sources in the State during a control period exceed the state assurance level or if a common designated representative's share of total NO_x emissions from the TR NO_x Annual units at TR NO_x Annual sources in the state during a control period exceeds the common designated representative's assurance level.
 - (v). To the extent the owners and operators fail to hold TR NO_x Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,
 - (A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
 - (B). Each TR NO_x Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.
- (3) Compliance periods.
- (i). A TR NO_x Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.
 - (ii). A TR NO_x Annual unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.
- (4) Vintage of allowances held for compliance.
- (i). A TR NO_x Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a TR NO_x Annual allowance that was allocated for such control period or a control period in a prior year.

- (ii). A TR NO_x Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NO_x Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.
- (5) Allowance Management System requirements. Each TR NO_x Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA.
- (6) Limited authorization. A TR NO_x Annual allowance is a limited authorization to emit one ton of NO_x during the control period in one year. Such authorization is limited in its use and duration as follows:
 - (i). Such authorization shall only be used in accordance with the TR NO_x Annual Trading Program; and
 - (ii). Notwithstanding any other provision of 40 CFR part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
- (7) Property right. A TR NO_x Annual allowance does not constitute a property right.

G.4 NO_x ozone season requirements

- (1) TR NO_x Ozone Season emissions limitation.
 - (i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_x Ozone Season source and each TR NO_x Ozone Season unit at the source shall hold, in the source's compliance account, TR NO_x Ozone Season allowances available for deduction for such control period under 40 CFR 97.524(a) in an amount not less than the tons of total NO_x emissions for such control period from all TR NO_x Ozone Season units at the source.
 - (ii). If total NO_x emissions during a control period in a given year from the TR NO_x Ozone Season units at a TR NO_x Ozone Season source are in excess of the TR NO_x Ozone Season emissions limitation set forth in paragraph (d)(1)(i) above, then:
 - (A). The owners and operators of the source and each TR NO_x Ozone Season unit at the source shall hold the TR NO_x Ozone Season allowances required for deduction under 40 CFR 97.524(d); and
 - (B). The owners and operators of the source and each TR NO_x Ozone Season unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBB and the Clean Air Act.
- (2) TR NO_x Ozone Season assurance provisions.
 - (i). If total NO_x emissions during a control period in a given year from all TR NO_x Ozone Season units at TR NO_x Ozone Season sources in the state exceed the

state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_x emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_x Ozone Season allowances available for deduction for such control period under 40 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 NO_x emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_x emissions exceeds the respective common designated representative's assurance level; and
 - (B). The amount by which total NO_x emissions from all TR NO_x Ozone Season units at TR NO_x Ozone Season sources in the state for such control period exceed the state assurance level.
- (ii). The owners and operators shall hold the TR NO_x Ozone Season allowances required under paragraph (d)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.
 - (iii). Total NO_x emissions from all TR NO_x Ozone Season units at TR NO_x Ozone Season sources in the state during a control period in a given year exceed the state assurance level if such total NO_x emissions exceed the sum, for such control period, of the State NO_x Ozone Season trading budget under 40 CFR 97.510(a) and the state's variability limit under 40 CFR 97.510(b).
 - (iv). It shall not be a violation of 40 CFR part 97, subpart BBBBBB or of the Clean Air Act if total NO_x emissions from all TR NO_x Ozone Season units at TR NO_x Ozone Season sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total NO_x emissions from the TR NO_x Ozone Season units at TR NO_x Ozone Season sources in the state during a control period exceeds the common designated representative's assurance level.
 - (v). To the extent the owners and operators fail to hold TR NO_x Ozone Season allowances for a control period in a given year in accordance with paragraphs (d)(2)(i) through (iii) above,
 - (A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
 - (B). Each TR NO_x Ozone Season allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (d)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBBB and the Clean Air Act.

- (3) Compliance Periods.
- (i). A TR NOx Ozone Season unit shall be subject to the requirements under paragraph (d)(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certificate requirements under 40 CFR 97.530(b) and for each control period thereafter.
 - (ii). A TR NOx Ozone Season unit shall be subject to the requirements under paragraph (d)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.530(b) and for each control period thereafter.
- (4) Vintage of allowances held for compliance.
- (i). A TR NOx Ozone Season allowance held for compliance with the requirements under paragraph (d)(1)(i) above for a control period in a given year must be a TR NOx Ozone Season Allowance that was allocated for such control period or a control period in a prior year.
 - (ii). A TR NOx Ozone Season allowance held for compliance with the requirements under paragraphs (d)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NOx Ozone Season allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.
- (5) Allowances Management System Requirements.
- (i). Each TR NOx Ozone Season allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart BBBBB.
- (6) Limited Authorization.
- (i). A TR NOx Ozone Season allowance is a limited authorization to emit one ton of NOx during the control period in one year. Such authorization is limited in its use and duration as follows:
 - (A). Such authorization shall only be used in accordance with the TR NOx Ozone Season Trading Program; and
 - (B). Notwithstanding any other provision of 40 CFR Part 97, Subpart BBBBB, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
- (7) Property Right.
- (i). A TR NOx Ozone Season allowance does not constitute a property right.

G.5 SO₂ emissions requirements

- (1) TR SO₂ Group 1 emissions limitation.

- (i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO₂ Group 1 source and each TR SO₂ Group 1 unit at the source shall hold, in the source's compliance account, TR SO₂ Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO₂ emissions for such control period from all TR SO₂ Group 1 units at the source.
 - (ii). If total SO₂ emissions during a control period in a given year from the TR SO₂ Group 1 units at a TR SO₂ Group 1 source are in excess of the TR SO₂ Group 1 emissions limitation set forth in paragraph (e)(1)(i) above, then:
 - (A). The owners and operators of the source and each TR SO₂ Group 1 unit at the source shall hold the TR SO₂ Group 1 allowances required for deduction under 40 CFR 97.624(d); and
 - (B). The owners and operators of the source and each TR SO₂ Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR part 97, subpart CCCCC and the Clean Air Act.
- (2) TR SO₂ Group 1 assurance provisions
- (i). If total SO₂ emissions during a control period in a given year from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO₂ emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO₂ Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—
 - (A). The quotient of the amount by which the common designated representative's share of such SO₂ emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such SO₂ emissions exceeds the respective common designated representative's assurance level; and
 - (B). The amount by which total SO₂ emissions from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state for such control period exceed the state assurance level.
 - (ii). The owners and operators shall hold the TR SO₂ Group 1 allowances required under paragraph (e)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

- (iii). Total SO₂ emissions from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO₂ emissions exceed the sum, for such control period, of the state SO₂ Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).
 - (iv). It shall not be a violation of 40 CFR part 97, subpart CCCCC or of the Clean Air Act if total SO₂ emissions from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total SO₂ emissions from the TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.
 - (v). To the extent the owners and operators fail to hold TR SO₂ Group 1 allowances for a control period in a given year in accordance with paragraphs (e)(2)(i) through (iii) above,
 - (A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
 - (B). Each TR SO₂ Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (e)(2)(i) through (iii) 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.
- (3) Compliance periods.
- (i). A TR SO₂ Group 1 unit shall be subject to the requirements under paragraph (e)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.
 - (ii). A TR SO₂ Group 1 unit shall be subject to the requirements under paragraph (e)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.
- (4) Vintage of allowances held for compliance.
- (i). A TR SO₂ Group 1 allowance held for compliance with the requirements under paragraph (e)(1)(i) 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.
 - (ii). A TR SO₂ Group 1 allowance held for compliance with the requirements under paragraphs (e)(1)(ii)(A) and (2)(i) through (iii) 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.
- (5) 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.

- (6) 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:
- (i). Such authorization shall only be used in accordance with the TR SO₂ Group 1 Trading Program; and
 - (ii). Notwithstanding any other provision of 40 CFR part 97, subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
- (7) Property right. A TR SO₂ Group 1 allowance does not constitute a property right.

G.6 Title V Permit Revision Requirements

- (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_x Annual allowances in accordance with 40 CFR part 97, subpart AAAAA, TR NO_x Ozone Season allowances in accordance with 40 CFR part 97, subpart BBBB, and TR SO₂ Group 1 allowances in accordance with 40 CFR part 97, subpart CCCCC.
- (2) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, 40 CFR 97.530 through 97.535, and 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2), 40 CFR 97.506(d)(2), and 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

G.7 Additional recordkeeping and reporting requirements

- (1) Unless otherwise provided, the owners and operators of each TR NO_x Annual source and each TR NO_x Annual unit, TR NO_x Ozone Season source and each TR NO_x Ozone Season unit, and TR SO₂ Group 1 source and each TR SO₂ Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.
- (i). The certificate of representation under 40 CFR 97.416, 40 CFR 97.516, and 40 CFR 97.616 for the designated representative for the source and each TR NO_x Annual unit, TR NO_x Ozone Season unit, and TR SO₂ Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416, 40 CFR 97.516, and 40 CFR 97.616 changing the designated representative.
 - (ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA, 40 CFR part 97, subpart BBBB, and 40 CFR part 97, subpart CCCCC.

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

(2) The designated representative of a TR NO_x Annual source and each TR NO_x Annual unit, a TR NO_x Ozone Season source and each TR NO_x 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 NO_x Annual Trading Program, TR NO_x Ozone Season Trading Program, and TR SO₂ Group 1 Trading Program, except as provided in 40 CFR 97.418, 40 CFR 97.518, and 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

G.8 Liability

- (1) Any provision of the TR NO_x Annual Trading Program that applies to a TR NO_x Annual source or the designated representative of a TR NO_x Annual source shall also apply to the owners and operators of such source and of the TR NO_x Annual units at the source.
- (2) Any provision of the TR NO_x Annual Trading Program that applies to a TR NO_x Annual unit or the designated representative of a TR NO_x Annual unit shall also apply to the owners and operators of such unit.
- (3) Any provision of the TR NO_x Ozone Season Trading Program that applies to a TR NO_x Ozone Season source or the designated representative of a TR NO_x Ozone Season source shall also apply to the owners and operators of such source and of the TR NO_x Ozone Season units at the source.
- (4) Any provision of the TR NO_x Ozone Season Trading Program that applies to a TR NO_x Ozone Season unit or the designated representative of a TR NO_x Ozone Season unit shall also apply to the owners and operators of such unit.
- (5) Any provision of the TR SO₂ Group 1 Trading Program that applies to a TR SO₂ Group 1 source or the designated representative of a TR SO₂ Group 1 source shall also apply to the owners and operators of such source and of the TR SO₂ Group 1 units at the source.
- (6) Any provision of the TR SO₂ Group 1 Trading Program that applies to a TR SO₂ Group 1 unit or the designated representative of a TR SO₂ Group 1 unit shall also apply to the owners and operators of such unit.

G.9 Effect on other authorities

No provision of the TR NO_x Annual Trading Program or exemption under 40 CFR 97.405, TR NO_x Ozone Season Trading Program or exemption under 40 CFR 97.505, and TR SO₂ 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_x Annual source or TR NO_x Annual unit, TR NO_x Ozone Season source or TR NO_x Ozone Season unit, and TR SO₂ Group 1 source or TR SO₂ 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.

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

ORIS Code: 6113

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

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) [This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 4.

Boiler No. 4 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 4.

Boiler No. 5 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)
 [This facility is an affected source under 40 CFR 63, Subpart UUUUU]

(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)]

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

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

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

(a) The owners and operators of each CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x ozone season source and CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x ozone season unit shall operate each source and unit in compliance with this CAIR permit.

(b) The CAIR NO_x unit(s), CAIR SO₂ unit(s), and CAIR NO_x ozone season unit(s) subject to this CAIR permit are Boiler 1, Boiler 2, Boiler 3, Boiler 4 and Boiler 5.

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

(a) The owners and operators, and the CAIR designated representative, of each CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x ozone season source and CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x ozone season unit at the source shall comply with the applicable monitoring, reporting, and record keeping requirements of 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) The emissions measurements recorded and reported in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 shall be used to determine compliance by each CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x ozone season source with the CAIR NO_x emissions limitation under 326 IAC 24-1-4(c), CAIR SO₂ emissions limitation under 326 IAC 24-2-4(c), and CAIR NO_x ozone season emissions limitation under 326 IAC 24-3-4(c) and Condition I.4.1, Nitrogen Oxides Emission Requirements, Condition I.4.2, Sulfur Dioxide Emission Requirements, and Condition I.4.3, Nitrogen Oxides Ozone Season Emission Requirements.

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

- (a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_x source and each CAIR NO_x unit at the source shall hold, in the source's compliance account, CAIR NO_x allowances available for compliance deductions for the control period under 326 IAC 24-1-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_x units at the source, as determined in accordance with 326 IAC 24-1-11.
- (b) A CAIR NO_x unit shall be subject to the requirements under 326 IAC 24-1-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-1-4(c)(2), and for each control period thereafter.
- (c) A CAIR NO_x allowance shall not be deducted for compliance with the requirements under 326 IAC 24-1-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_x allowance was allocated.
- (d) CAIR NO_x allowances shall be held in, deducted from, or transferred into or among CAIR NO_x allowance tracking system accounts in accordance with 326 IAC 24-1-9, 326 IAC 24-1-10, and 326 IAC 24-1-12.
- (e) A CAIR NO_x allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_x annual trading program. No provision of the CAIR NO_x annual trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-1-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.
- (f) A CAIR NO_x allowance does not constitute a property right.
- (g) Upon recordation by the U.S. EPA under 326 IAC 24-1-8, 326 IAC 24-1-9, 326 IAC 24-1-10, or 326 IAC 24-1-12, every allocation, transfer, or deduction of a CAIR NO_x allowance to or from a CAIR NO_x source's compliance account is incorporated automatically in this CAIR permit.

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

- (a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO₂ source and each CAIR SO₂ unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR SO₂ allowances available for compliance deductions for the control period under 326 IAC 24-2-8(j) and 326 IAC 24-2-8(k) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO₂ units at the source, as determined in accordance with 326 IAC 24-2-10.
- (b) A CAIR SO₂ unit shall be subject to the requirements under 326 IAC 24-2-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-2-4(c)(2), and for each control period thereafter.
- (c) A CAIR SO₂ allowance shall not be deducted for compliance with the requirements under 326 IAC 24-2-4(c)(1), for a control period in a calendar year before the year for which the CAIR SO₂ allowance was allocated.
- (d) CAIR SO₂ allowances shall be held in, deducted from, or transferred into or among CAIR SO₂ allowance tracking system accounts in accordance with 326 IAC 24-2-8, 326 IAC 24-2-9, and 326 IAC 24-2-11.

- (e) A CAIR SO₂ allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO₂ trading program. No provision of the CAIR SO₂ trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-2-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.
- (f) A CAIR SO₂ allowance does not constitute a property right.
- (g) Upon recordation by the U.S. EPA under 326 IAC 24-2-8, 326 IAC 24-2-9, or 326 IAC 24-2-11, every allocation, transfer, or deduction of a CAIR SO₂ allowance to or from a CAIR SO₂ source's compliance account is incorporated automatically in this CAIR permit.

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

- (a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_x ozone season source and each CAIR NO_x ozone season unit at the source shall hold, in the source's compliance account, CAIR NO_x ozone season allowances available for compliance deductions for the control period under 326 IAC 24-3-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_x ozone season units at the source, as determined in accordance with 326 IAC 24-3-11.
- (b) A CAIR NO_x ozone season unit shall be subject to the requirements under 326 IAC 24-3-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-3-4(c)(2), and for each control period thereafter.
- (c) A CAIR NO_x ozone season allowance shall not be deducted for compliance with the requirements under 326 IAC 24-3-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_x ozone season allowance was allocated.
- (d) CAIR NO_x ozone season allowances shall be held in, deducted from, or transferred into or among CAIR NO_x ozone season allowance tracking system accounts in accordance with 326 IAC 24-3-9, 326 IAC 24-3-10, and 326 IAC 24-3-12.
- (e) A CAIR NO_x ozone season allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_x ozone season trading program. No provision of the CAIR NO_x ozone season trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-3-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.
- (f) A CAIR NO_x ozone season allowance does not constitute a property right.
- (g) Upon recordation by the U.S. EPA under 326 IAC 24-3-8, 326 IAC 24-3-9, 326 IAC 24-3-10, or 326 IAC 24-3-12, every allocation, transfer, or deduction of a CAIR NO_x ozone season allowance to or from a CAIR NO_x ozone season source's compliance account is incorporated automatically in this CAIR permit.

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

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

- (1) Surrender the CAIR NO_x allowances required for deduction under 326 IAC 24-1-9(j)(4).
- (2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

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

- (b) The owners and operators of a CAIR SO₂ source and each CAIR SO₂ unit that emits sulfur dioxide during any control period in excess of the CAIR SO₂ emissions limitation shall do the following:

- (1) Surrender the CAIR SO₂ allowances required for deduction under 326 IAC 24-2-8(k)(4).
- (2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

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

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

- (1) Surrender the CAIR NO_x ozone season allowances required for deduction under 326 IAC 24-3-9(j)(4).
- (2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

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

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

Unless otherwise provided, the owners and operators of the CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x ozone season source and each CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x ozone season unit at the source shall keep on site at the source or at a central location within Indiana for those owners or operators with unattended sources, each of the following documents for a period of five (5) years from the date the document was created:

- (a) The certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), and 326 IAC 24-3-6(h) for the CAIR designated representative for the source and each CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x ozone season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation. The certificate and documents shall be retained on site at the source or at a central location within Indiana for those owners or operators with unattended sources beyond such five (5) year period until such documents are superseded because of the submission of a new account certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), and 326 IAC 24-3-6(h) changing the CAIR designated representative.

- (b) All emissions monitoring information, in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11, provided that to the extent that 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 provides for a three (3) year period for record keeping, the three (3) year period shall apply.
- (c) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_x annual trading program, CAIR SO₂ trading program, and CAIR NO_x ozone season trading program.
- (d) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_x annual trading program, CAIR SO₂ trading program, and CAIR NO_x ozone season trading program or to demonstrate compliance with the requirements of the CAIR NO_x annual trading program, CAIR SO₂ trading program, and CAIR NO_x ozone season trading program.

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

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

-
- (a) The CAIR designated representative of the CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x ozone season source and each CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x ozone season unit at the source shall submit the reports required under the CAIR NO_x annual trading program, CAIR SO₂ trading program, and CAIR NO_x ozone season trading program, including those under 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.
 - (b) Pursuant to 326 IAC 24-1-4(e), 326 IAC 24-2-4(e), and 326 IAC 24-3-4(e) and 326 IAC 24-1-6(e)(1), 326 IAC 24-2-6(e)(1), and 326 IAC 24-3-6(e)(1), each submission under the CAIR NO_x annual trading program, CAIR SO₂ trading program, and CAIR NO_x ozone season trading program shall include the following certification statement by the CAIR designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."
 - (c) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to IDEM, OAQ, the information 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
 - (d) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to U.S. EPA, the information shall be submitted to:

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

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

The owners and operators of each CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x ozone season source and each CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x ozone season unit shall be liable as follows:

- (a) Each CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x ozone season source and each CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x ozone season unit shall meet the requirements of the CAIR NO_x annual trading program, CAIR SO₂ trading program, and CAIR NO_x ozone season trading program, respectively.
- (b) Any provision of the CAIR NO_x annual trading program, CAIR SO₂ trading program, and CAIR NO_x ozone season trading program that applies to a CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x ozone season source or the CAIR designated representative of a CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x ozone season source shall also apply to the owners and operators of such source and of the CAIR NO_x units, CAIR SO₂ units, and CAIR NO_x ozone season units at the source.
- (c) Any provision of the CAIR NO_x annual trading program, CAIR SO₂ trading program, and CAIR NO_x ozone season trading program that applies to a CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x ozone season unit or the CAIR designated representative of a CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x ozone season unit shall also apply to the owners and operators of such unit.

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

No provision of the CAIR NO_x annual trading program, CAIR SO₂ trading program, and CAIR NO_x ozone season trading program, a CAIR permit application, a CAIR permit, or an exemption under 326 IAC 24-1-3, 326 IAC 24-2-3, and 326 IAC 24-3-3 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x ozone season source or CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x ozone season unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act (CAA).

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

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

- (a) Except as specified in 326 IAC 24-1-6(f)(3), 326 IAC 24-2-6(f)(3), and 326 IAC 24-3-6(f)(3), each CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x ozone season source, including all CAIR NO_x units, CAIR SO₂ units, and CAIR NO_x ozone season units at the source, shall have one (1) and only one (1) CAIR designated representative, with regard to all matters under the CAIR NO_x annual trading program, CAIR SO₂ trading program, and CAIR NO_x ozone season trading program concerning the source or any CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x ozone season unit at the source.

- (b) The provisions of 326 IAC 24-1-6(f), 326 IAC 24-2-6(f), and 326 IAC 24-3-6(f) shall apply where the owners or operators of a CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x ozone season source choose to designate an alternate CAIR designated representative.

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

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

Source Name: Duke Energy Indiana, LLC - Gibson Generating Station
Source Address: 1097 N 950 W, Owensville, Indiana 47665
Part 70 Permit No.: T051-33624-00013

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

- Annual Compliance Certification Letter
- Test Result (specify)
- Report (specify)
- Notification (specify)
- Affidavit (specify)
- Other (specify)

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:

Printed Name:

Title/Position:

Phone:

Date:

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

**PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT**

Source Name: Duke Energy Indiana, LLC - Gibson Generating Station
Source Address: 1097 N 950 W, Owensville, Indiana 47665
Part 70 Permit No.: T051-33624-00013

This form consists of 2 pages

Page 1 of 2

<input type="checkbox"/> This is an emergency as defined in 326 IAC 2-7-1(12) <ul style="list-style-type: none"> • The Permittee must notify the Office of Air Quality (OAQ), within four (4) business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and • The Permittee must submit notice in writing or by facsimile within two (2) working days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.

If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:
Control Equipment:
Permit Condition or Operation Limitation in Permit:
Description of the Emergency:
Describe the cause of the Emergency:

If any of the following are not applicable, mark N/A

Page 2 of 2

Date/Time Emergency started:
Date/Time Emergency was corrected:
Was the facility being properly operated at the time of the emergency? Y N
Type of Pollutants Emitted: TSP, PM-10, SO ₂ , VOC, NO _x , CO, Pb, other:
Estimated amount of pollutant(s) emitted during emergency:
Describe the steps taken to mitigate the problem:
Describe the corrective actions/response steps taken:
Describe the measures taken to minimize emissions:
If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:

Form Completed by: _____

Title / Position: _____

Date: _____

Phone: _____

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

Part 70 Quarterly Report

Source Name: Duke Energy Indiana, LLC - Gibson Generating Station
 Source Address: 1097 N 950 W, Owensville, Indiana 47665
 Part 70 Permit No.: T051-33624-00013
 Facility: Exhauster 3A, Exhauster 3B, Exhauster 3C (spare) Exhauster 1A, Exhauster 1B, Exhauster 2A, Exhauster 2B, Spare Exhauster, (B3) Remote Fly Ash Silo A Bin Vent Filter and (B4) Remote Fly Ash Silo B Bin Vent Filter
 Pollutants: PM, PM₁₀ and PM_{2.5}
 Parameter: Number of hours of operation
 Limit: Less than 4745 hours each per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER :

YEAR:

Month	Number of Hours of Operation	Number of Hours of Operation	Number of Hours of Operation
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

No deviation occurred in this quarter.

Deviation/s occurred in this quarter.

Deviation has been reported on:

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

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

Part 70 Quarterly Report

Source Name: Duke Energy Indiana, LLC - Gibson Generating Station
Source Address: 1097 N 950 W, Owensville, Indiana 47665
Part 70 Permit No.: T051-33624-00013
Facility: U1 Bin Vent Filter and U2 Bin Vent Filter
Pollutants: PM, PM₁₀ and PM_{2.5}
Parameter: Number of hours of operation
Limit: Less than 5840 hours each per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER :

YEAR:

Month	Number of Hours of Operation	Number of Hours of Operation	Number of Hours of Operation
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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

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

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

Part 70 Quarterly Report

Source Name: Duke Energy Indiana, LLC - Gibson Generating Station
Source Address: 1097 N 950 W, Owensville, Indiana 47665
Part 70 Permit No.: T051-33624-00013
Facility: Lime Silo A Bin Vent Filter and Lime Silo B Bin Vent Filter
Pollutants: PM, PM₁₀ and PM_{2.5}
Parameter: Number of hours of operation
Limit: Less than 2920 hours each per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER :

YEAR:

Month	Number of Hours of Operation	Number of Hours of Operation	Number of Hours of Operation
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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

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

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

Part 70 Quarterly Report

Source Name: Duke Energy Indiana, LLC - Gibson Generating Station
Source Address: 1097 N 950 W, Owensville, Indiana 47665
Part 70 Permit No.: T051-33624-00013
Facility: Fly Ash Day Bin vent Filter
Pollutants: PM, PM₁₀ and PM_{2.5}
Parameter: Number of hours of operation
Limit: Less than 8760 hours each per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER :

YEAR:

Month	Number of Hours of Operation	Number of Hours of Operation	Number of Hours of Operation
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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

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

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

Part 70 Quarterly Report

Source Name: Duke Energy Indiana, LLC - Gibson Generating Station
Source Address: 1097 N 950 W, Owensville, Indiana 47665
Part 70 Permit No.: T051-33624-00013
Facility: One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No.1
Pollutants: SO₂
Parameter: Daily Average SO₂ emission rate in lb/MMBtu
Limit: SO₂ emissions from Boiler No.1 shall not exceed 3.19 pounds per million Btu (lb/MMBtu) based on a thirty (30) day rolling weighted average.

QUARTER :

YEAR:

Month	Number of Hours of Operation	Number of Hours of Operation	Number of Hours of Operation
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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

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

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

Part 70 Quarterly Report

Source Name: Duke Energy Indiana, LLC - Gibson Generating Station
Source Address: 1097 N 950 W, Owensville, Indiana 47665
Part 70 Permit No.: T051-33624-00013
Facility: One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No.2
Pollutants: SO₂
Parameter: Daily Average SO₂ emission rate in lb/MMBtu
Limit: SO₂ emissions from Boiler No.2 shall not exceed 3.19 pounds per million Btu (lb/MMBtu) based on a thirty (30) day rolling weighted average.

QUARTER :

YEAR:

Month	Number of Hours of Operation	Number of Hours of Operation	Number of Hours of Operation
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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

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

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

Part 70 Quarterly Report

Source Name: Duke Energy Indiana, LLC - Gibson Generating Station
 Source Address: 1097 N 950 W, Owensville, Indiana 47665
 Part 70 Permit No.: T051-33624-00013
 Facility: One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No.3
 Pollutants: SO₂
 Parameter: Daily Average SO₂ emission rate in lb/MMBtu
 Limit: SO₂ emissions from Boiler No.3 shall not exceed 3.19 pounds per million Btu (lb/MMBtu) based on a thirty (30) day rolling weighted average.

QUARTER :

YEAR:

Month	Number of Hours of Operation	Number of Hours of Operation	Number of Hours of Operation
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

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

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

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

Part 70 Quarterly Report

Source Name: Duke Energy Indiana, LLC - Gibson Generating Station
Source Address: 1097 N 950 W, Owensville, Indiana 47665
Part 70 Permit No.: T051-33624-00013
Facility: One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No.4
Pollutants: SO₂
Parameter: 30 day rolling weighted average SO₂ emission rate in lb/MMBtu
Limit: SO₂ emissions from Boiler No. 4 stack shall not exceed 0.60 pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average and operate an FGD system.

QUARTER :

YEAR:

Month	Number of Hours of Operation	Number of Hours of Operation	Number of Hours of Operation
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

No deviation occurred in this quarter.

Deviation/s occurred in this quarter.

Deviation has been reported on:

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

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

Part 70 Quarterly Report

Source Name: Duke Energy Indiana, LLC - Gibson Generating Station
 Source Address: 1097 N 950 W, Owensville, Indiana 47665
 Part 70 Permit No.: T051-33624-00013
 Facility: One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No.5
 Pollutants: SO₂
 Parameter: 30 day rolling weighted average SO₂ emission rate in lb/MMBtu
 Limit: SO₂ emissions from Boiler No. 5 stack shall not exceed 1.10 pounds per million Btu (lbs/MMBtu) based on a twenty-four (24) hour average and operation of an FGD system.

QUARTER :

YEAR:

Month	Number of Hours of Operation	Number of Hours of Operation	Number of Hours of Operation
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

No deviation occurred in this quarter.

Deviation/s occurred in this quarter.
 Deviation has been reported on:

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

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
 OFFICE OF AIR QUALITY
 COMPLIANCE AND ENFORCEMENT BRANCH
 PART 70 OPERATING PERMIT
 QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT**

Source Name: Duke Energy Indiana, LLC - Gibson Generating Station
 Source Address: 1097 N 950 W, Owensville, Indiana 47665
 Part 70 Permit No.: T051-33624-00013

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

<p>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".</p>	
<input type="checkbox"/> NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.	
<input type="checkbox"/> THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD	
<p>Permit Requirement (specify permit condition #)</p>	
<p>Date of Deviation:</p>	<p>Duration of Deviation:</p>
<p>Number of Deviations:</p>	
<p>Probable Cause of Deviation:</p>	
<p>Response Steps Taken:</p>	
<p>Permit Requirement (specify permit condition #)</p>	
<p>Date of Deviation:</p>	<p>Duration of Deviation:</p>
<p>Number of Deviations:</p>	
<p>Probable Cause of Deviation:</p>	
<p>Response Steps Taken:</p>	

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

Form Completed by: _____

Title / Position: _____

Date: _____

Phone: _____

Attachment F

Part 70 Operating Permit No: T051-36994-00013

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Title 40: Protection of Environment

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

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Source: 77 FR 9464, Feb. 16, 2012, unless otherwise noted.

What This Subpart Covers

§63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in §63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

§63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in §63.10042 of this subpart.

§63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, or existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

(1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs, as defined in §63.10042, within a subcategory.

(2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in §63.10042.

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in §63.2, and if you commence reconstruction after May 3, 2011.

(d) An EGU is existing if it is not new or reconstructed. An existing electric steam generating unit that meets the applicability requirements after the effective date of this final rule due to a change in process (e.g., fuel or utilization) is considered to be an existing source under this subpart.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013]

§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]

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012]

Emission Limitations and Work Practice Standards

§63.9990 What are the subcategories of EGUs?

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (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.

(l) On or before the date an EGU is subject to this subpart, you must install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.

(m) Should you choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for your EGU, on or before the date your EGU is subject to this subpart, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with §63.10020(e).

(1) You may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system.

(2) You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.

(n) If you have permanently converted your EGU from coal or oil to natural gas or biomass after your compliance date (or, if applicable, after your approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents you from operating in a manner that would subject you to this subpart, you are no longer subject to this subpart, notwithstanding the coal or oil usage in the previous calendar years. The date on which you are no longer subject to this subpart is the date on which you converted to natural gas or biomass firing; it is also the date on which you must be in compliance with any newly applicable standards.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013; 79 FR 68788, Nov. 19, 2014; 81 FR 20180, Apr. 6, 2016]

§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_{hj} in Equation 19-19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS:

(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 part 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A-1 and A-2 to part 60 of this chapter, or a flow rate monitor that has been certified according to part 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A-1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to part 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from §75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under §75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly gross output data (megawatts), from facility records.

(ii) If you use CEMS to measure CO₂ (or O₂) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in µg/m³ (dry basis), for 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_h”, “Q_h”, “B_{ws}” and “(MW)_h” with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

(1) Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10⁻⁶ to convert it to TBtu/hr; or

(2) Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10⁻³ to convert it to GW; or

(3) If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).

(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (*i.e.*, either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

(i) *Liquid-oil fuel moisture measurement.* If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraphs (i)(1) through (5) of this section.

(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or

(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(i) ASTM D95-05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," or

(ii) ASTM D4006-11, "Standard Test Method for Water in Crude Oil by Distillation," including Annex A1 and Appendix A1.

(5) Use one of the following methods to obtain fuel moisture samples:

(i) ASTM D4177-95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," including Annexes A1 through A6 and Appendices X1 and X2, or

(ii) ASTM D4057-06 (Reapproved 2011), "Standard Practice for Manual Sampling of Petroleum and Petroleum Products," including Annex A1.

(6) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in §63.10000(c)(2)(iii)) or

(ii) Use an HCl CEMS and/or HF CEMS.

(j) Startup and shutdown for coal-fired or solid oil derived-fired units. You must follow the requirements given in Table 3 to this subpart.

(k) You must submit a Notification of Compliance Status summarizing the results of your initial compliance demonstration, as provided in §63.10030.

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§63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS 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.

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§63.10007 What methods and other procedures must I use for the performance tests?

(a) Except as otherwise provided in this section, you must conduct all required performance tests according to §63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in §63.7(c).

(1) If you use CEMS (Hg, HCl, SO₂, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, you must collect quality- assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 to this subpart), except as otherwise provided in §63.10020(b). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §§63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii).

(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non Hg metals emissions limit, 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 1.66×10^{-7} ;

(ii) Multiply HCl ppm by 9.43×10^{-8} ;

(iii) Multiply HF ppm by 5.18×10^{-8} ;

(iv) Multiply HAP metals concentrations (mg/dscm) by 6.24×10^{-8} ; and

(v) Multiply Hg concentrations (µg/scm) by 6.24×10^{-11} .

(3) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A-2 or A-3 in appendix A to this subpart (as applicable). In all other cases,

use an equation that has the general form of Equation A-2 or A-3, replacing the value of K with 1.66×10^{-7} lb/scf-ppm for SO₂, 9.43×10^{-8} lb/scf-ppm for HCl (if an HCl CEMS is used), 5.18×10^{-8} lb/scf-ppm for HF (if an HF CEMS is used), or 6.24×10^{-8} lb-scm/mg-scf for HAP metals and for HCl and HF (when performance stack testing is used), and defining C_n as the average SO₂, HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A-4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define (M)_h as the calculated pollutant mass emission rate for the performance test (lb/h), and define (MW)_h as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the 10³ term from Equation A-4 to determine the pollutant emission rate in lb/MWh.

(f) If you elect to (or are required to) use CEMS to continuously monitor Hg, HCl, HF, SO₂, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). For the purposes of this subpart, these default values are not considered to be substitute data.

(1) *Diluent cap values.* If you use CEMS (or, if applicable, sorbent trap monitoring systems) to comply with a heat input-based emission rate limit, you may use the following diluent cap values for a startup or shutdown hour in which the measured CO₂ concentration is below the cap value or the measured O₂ concentration is above the cap value:

(i) For an IGCC EGU, you may use 1% for CO₂ or 19% for O₂.

(ii) For all other EGUs, you may use 5% for CO₂ or 14% for O₂.

(2) *Default gross output.* If you use CEMS to continuously monitor Hg, HCl, HF, SO₂, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default value is available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). For the purposes of this subpart, this default value is not considered to be substitute data. For a startup or shutdown hour in which there is heat input to an affected EGU but zero gross output, you must calculate the pollutant emission rate using a value equivalent to 5% of the maximum sustainable gross output, expressed in megawatts, as defined in section 6.5.2.1(a)(1) of appendix A to part 75 of this chapter. This default gross output is either the nameplate capacity of the EGU or the highest gross output observed in at least four representative quarters of EGU operation. For a monitored common stack, the default gross output is used only when all EGUs are operating (*i.e.*, combusting fuel) are in startup or shutdown mode, and have zero electrical generation. Under those conditions, a default gross output equal to 5% of the combined maximum sustainable gross output of the EGUs that are operating but have a total of zero gross output must be used to calculate the hourly gross output-based pollutant emissions rate.

(g) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.

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§63.10008 [Reserved]

§63.10009 May I use emissions averaging to comply with this subpart?

(a) *General eligibility.* (1) You may use emissions averaging as described in paragraph (a)(2) of this section as an alternative to meeting the requirements of §63.9991 for filterable PM, SO₂, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if:

(i) You have more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control); and

(ii) You use CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance.

(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the “unit designed for coal $\geq 8,300$ Btu/lb” subcategory are equal to or less than 1.2 lb/TBtu or 1.3E-2 lb/GWh on a 30-boiler operating day basis or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the “unit designed for coal $\geq 8,300$ Btu/lb” subcategory, the averaging time for emissions averaging for pollutants is 30 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 $\geq 8,300$ 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.*

$$WAER_m = \frac{[\sum_{j=1}^p Herm_j \times Rmm_j] + \sum_{k=1}^m Ter_k \times Rmt_k}{(\sum_{j=1}^p Rmm_j) + \sum_{k=1}^m Rmt_k} \quad (Eq. 1a)$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = 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.

$$WAER_m = \frac{\sum [(\sum_{j=1}^p Herm_{i,j}) \times Smm_j \times Cfm_j] + \sum_{k=1}^m Ter_k \times Smt_k \times Cft_k}{\sum [\sum_{j=1}^p Smm_j \times Cfm_j] + \sum_{k=1}^m Smt_k \times Cft_k} \quad (Eq. 1b)$$

Where:

Variables with the similar names share the descriptions for Equation 1a of this section,

S_{mj} = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

C_{fmj} = conversion factor, calculated from the most recent compliance test results, in terms units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU j,

S_{mk} = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

C_{fmk} = conversion factor, calculated from the most recent compliance test results, in terms units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

(2) Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use Equation 2a or 2b of this section to calculate the 30 day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^p [\sum_{t=1}^n (Her_i \times Rm_i)]_p + \sum_{i=1}^m (Ter_i \times Rt_i)}{\sum_{i=1}^p [\sum_{t=1}^n (Rm_i)]_p + \sum_{i=1}^m Rt_i} \quad (Eq. 2a)$$

Where:

Her_i = hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hours that hourly rates are collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^p [\sum_{t=1}^n (Her_i \times S_{mi} \times C_{fm_i})]_p + \sum_{i=1}^m (Ter_i \times St_i \times C_{ft_i})}{\sum_{i=1}^p [\sum_{t=1}^n (S_{mi} \times C_{fm_i})]_p + \sum_{i=1}^m St_i \times C_{ft_i}} \quad (Eq. 2b)$$

Where:

variables with similar names share the descriptions for Equation 2a of this section,

S_{mi} = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

C_{fm_i} = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

C_{ft_i} = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the “coal-fired unit not low rank virgin coal” subcategory. Use Equation 3a or 3b of this section to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^p [\sum_{j=1}^n (Her_j \times Rm_i)]_p + \sum_{i=1}^m (Ter_i \times Rt_i)}{\sum_{i=1}^p [\sum_{j=1}^n (Rm_i)]_p + \sum_{i=1}^m Rt_i} \quad (\text{Eq. 3a})$$

Where:

Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hours that hourly rates are collected over the 90-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 90-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^p [\sum_{j=1}^n (Her_j \times Sm_i \times Cfm_i)]_p + \sum_{i=1}^m (Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^p [\sum_{j=1}^n (Sm_i \times Cfm_i)]_p + \sum_{i=1}^m St_i \times Cft_i} \quad (\text{Eq. 3b})$$

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,

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 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

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.

(c) *Separate stack requirements.* For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average filterable PM, SO₂, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (d) through (j) of this section.

(d) For each existing EGU in the averaging group:

(1) The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 180 days after April 16, 2015, or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; or

(2) The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(e) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the date that you begin emissions averaging.

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing your emissions averaging plan, you must conduct required emissions monitoring for 30- (or 90-) days of boiler operation and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with this section. If, before the start of your initial compliance demonstration, the Administrator becomes aware that you intend to use emissions averaging for that demonstration, or if your initial Notification of Compliance Status (NOCS) indicates that you intend to implement emissions averaging at a future date, the Administrator may require you to submit your proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

(1) You must use Equation 1a in paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO₂, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 to this subpart.

(2) If you are not capable of monitoring heat input or gross output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of paragraph (b) of this section as an alternative to using Equation 1a of paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO₂, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to paragraphs (g)(1) and (2) of this section. The first averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that you begin emissions averaging.

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option.

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

(h) *CEMS (or sorbent trap monitoring) use.* If an EGU in your emissions averaging group uses CEMS (or a sorbent trap monitor for Hg emissions) to demonstrate compliance, you must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate.

(i) *Emissions testing.* If you use manual emissions testing to demonstrate compliance for one or more EGUs in your emissions averaging group, you must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. You may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate.

(j) *Emissions averaging plan.* You must develop an implementation plan for emissions averaging according to the following procedures and requirements in paragraphs (j)(1) and (2) of this section.

(1) You must include the information contained in paragraphs (j)(1)(i) through (v) of this section in your implementation plan for all the emissions units included in an emissions averaging:

(i) The identification of all existing EGUs in the emissions averaging group, including for each either the applicable HAP emission level or the control technology installed as of 180 days after February 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; and the date on which you are requesting emissions averaging to commence;

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

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple EGUs, you must identify each EGU;

(iv) The means of measurement (e.g., CEMS, sorbent trap monitoring, manual performance test) of filterable PM, SO₂, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in §63.10007 and to be used in the emissions averaging calculations; and

(v) A demonstration that emissions averaging can produce compliance with each of the applicable emission limit(s) in accordance with paragraph (b)(1) of this section.

(2) If, as described in paragraph (f) of this section, the Administrator requests you to submit the averaging plan for review and approval, you must receive approval before initiating emissions averaging.

(i) The Administrator shall use following criteria in reviewing and approving or disapproving the plan:

(A) Whether the content of the plan includes all of the information specified in paragraph (j)(1) of this section; and

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

(ii) The Administrator shall not approve an emissions averaging implementation plan containing any of the following provisions:

(A) Any averaging between emissions of different pollutants or between units located at different facilities; or

(B) The inclusion of any emissions unit other than an existing unit in the same subcategory.

(k) *Common stack requirements.* For a group of two or more existing affected units, each of which vents through a single common stack, you may average emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (l) or (m) of this section.

(l) For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(m) For all other groups of units subject to paragraph (k) of this section, you may elect to conduct manual performance tests according to procedures specified in §63.10007 in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, you must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, you may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. You may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis.

(n) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (k) of this section may be treated as a single stack for purposes of paragraph (c) of this section and included in an emissions averaging group subject to paragraph (c) of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24085, Apr. 24, 2013; 81 FR 20183, Apr. 6, 2016]

§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.

(6) *Unit with multiple parallel control devices with multiple stacks.* If the flue gases from an affected unit, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, you shall install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in each of the multiple stacks. You shall calculate hourly flow-weighted average pollutant emission rates for the unit as follows:

- (i) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters;
 - (ii) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly stack gas flow rate at that stack or duct;
 - (iii) Sum the products determined under paragraph (a)(6)(ii) of this section; and
 - (iv) Divide the result obtained in paragraph (a)(6)(iii) of this section by the total hourly stack gas flow rate for the unit, summed across all of the stacks or ducts.
- (b) If you use an oxygen (O₂) or carbon dioxide (CO₂) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O₂ or CO₂ concentrations shall be monitored at a location that represents emissions to the atmosphere, *i.e.*, at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O₂ or CO₂ data in the emissions calculations; do not use part 75 substitute data values.
- (c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.
- (d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from §75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under §75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.
- (e) If you use an HCl and/or HF CEMS, you must install, certify, operate, maintain, and quality-assure the data from the monitoring system in accordance with appendix B to this subpart. Calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of appendix B to this subpart).

(f)(1) If you use an SO₂ CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO₂ CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO₂ CEMS has a span value of 30 ppm or less.

(3) Calculate and record a 30-boiler operating day rolling average SO₂ emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO₂ emission rates in the 30 boiler operating day period.

(4) Use only unadjusted, quality-assured SO₂ concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO₂ data and do not use part 75 substitute data values. For startup or shutdown hours (as defined in §63.10042) the default gross output and the diluent cap are available for use in the hourly SO₂ emission rate calculations, as described in §63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default gross output is used to calculate the SO₂ emission rate for any of these hours.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit, 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 $160^{\circ} \pm 14^{\circ} \text{C}$ ($320^{\circ} \pm 25^{\circ} \text{F}$). 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.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24086, Apr. 24, 2013; 79 FR 68789, Nov. 19, 2014; 81 FR 20185, Apr. 6, 2016]

§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.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 79 FR 68790, Nov. 19, 2014; 81 FR 20186, Apr. 6, 2016]

Continuous Compliance Requirements

§63.10020 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see §63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §§63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. You must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation from the monitoring requirements.

(e) Additional requirements during startup periods or shutdown periods if you choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for your EGU.

(1) During each period of startup, you must record for each EGU:

(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]

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 79 FR 68790, Nov. 19, 2014; 81 FR 20187, Apr. 6, 2016]

§63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

- (a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.

(b) Except as otherwise provided in §63.10020(c), if you use a CEMS to measure SO₂, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO₂, O₂, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.

$$\text{Boiler operating day average} = \frac{\sum_{i=1}^n Her_i}{n} \text{ (Eq. 8)}$$

Where:

Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

(c) If you use 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.

$$30 \text{ boiler operating day average} = \frac{\sum_{i=1}^n Hpv_i}{n} \text{ (Eq. 9)}$$

Where:

Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30 boiler operating days.

(1) For any exceedance of the 30-boiler operating day PM CPMS average value from the established operating parameter limit for an EGU subject to the emissions limits in Table 1 to this subpart, you must:

(i) Within 48 hours of the exceedance, visually inspect the air pollution control device (APCD);

(ii) If the inspection of the APCD identifies the cause of the exceedance, take corrective action as soon as possible, and return the PM CPMS measurement to within the established value; and

(iii) Within 45 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct any additional testing for any exceedances that occur between the time of the original exceedance and the PM emissions compliance test required under this paragraph.

(2) PM CPMS exceedances of the operating limit for an EGU subject to the emissions limits in Table 1 of this subpart leading to more than four required performance tests in a 12-month period (rolling monthly) constitute a separate violation of this subpart.

(d) If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 1 or 2 to this subpart, you

(1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year.

(2) Must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard; and

(3) Must conduct site-specific monitoring using CMS to demonstrate compliance with the site-specific monitoring requirements in Table 7 to this subpart pertaining to HCl and HF emissions from a liquid oil-fired EGU to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of §63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in §63.10020.

(e) Conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section. For your first tune-up, you may perform the burner inspection any time prior to the tune-up or you may delay the first burner inspection until the next scheduled EGU outage provided you meet the requirements of §63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months. If your EGU is offline when a deadline to perform the tune-up passes, you shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit.

(1) As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NO_x and CO must be installed within 3 calendar months after the burner inspection,

(ii) Burner or combustion control component parts that do not affect the ability to optimize NO_x and CO may be installed on a schedule determined by the operator;

(2) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

(3) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O₂ probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

(6) Optimize combustion to minimize generation of CO and NO_x. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_x optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

(7) While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO_x in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO_x and O₂ monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;

(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NO_x in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) 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.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24086, Apr. 24, 2013; 79 FR 68791, Nov. 19, 2014; 81 FR 20187, Apr. 6, 2016]

§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.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 79 FR 68791, Nov. 19, 2014]

§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.

$$\bar{x} = \frac{1}{n} \sum_{i=1}^n X_i, \bar{y} = \frac{1}{n} \sum_{i=1}^n Y_i \quad (\text{Eq. 10})$$

Where:

X_i = the PM CPMS data points for run i of the performance test,

Y_i = the PM emissions value (in lb/MWh) for run i of the performance test, and

n = the number of data points.

(C) With your PM CPMS instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM emissions value (in lb/MWh) from your compliance runs, determine a relationship of PM lb/MWh per milliamp with equation 11.

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

Where:

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

\bar{y} = the three run average PM lb/MWh,

\bar{x} = the three run average milliamp output from your PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (b)(2)(i)(A) of this section.

(D) Determine your source specific 30-day rolling average operating limit using the PM lb/MWh per milliamp value from equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

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

Where:

O_L = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps,

L = your source PM emissions limit in lb/MWh,

z = your instrument zero in milliamps, determined from (b)(2)(i)(A) of this section, and

R = the relative PM lb/MWh per milliamp for your PM CPMS, from equation 11.

(ii) If your PM compliance test demonstrates your PM emissions exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish your operating limit.

(A) Determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13.

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

Where:

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

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

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

(iv) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(v) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs.

(vi) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signal corresponding to each PM compliance test run.

(c) You must operate and maintain your process and control equipment such that the 30 operating day average PM CPMS output does not exceed the operating limit determined in paragraphs (a) and (b) of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24086, Apr. 24, 2013; 81 FR 20187, Apr. 6, 2016]

Notification, Reports, and Records

§63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you startup your EGU that is an affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.

(c) As specified in §63.9(b)(4) and (b)(5), if you startup your new or reconstructed EGU that is an affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the EGU that is an affected source.

(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) When you are required to conduct an initial compliance demonstration as specified in §63.10011(a), you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as applicable.

(1) A description of the affected source(s), including identification of the subcategory of the source, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (e.g., use of PM CPMS); CEMS; or a sorbent trap monitoring system.

(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation in the Notification of Compliance Status report.

(7) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following:

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with §63.10005(h)(1)(i), the date of each stack test conducted during the previous 3 years, a comparison of emission level you achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in §63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:

(A) "This EGU complies with the requirements in §63.10021(a) to demonstrate continuous compliance." and

(B) "No secondary materials that are solid waste were combusted in any affected unit."

(iii) For each of your existing EGUs, identification of each emissions limit as specified in Table 2 to this subpart with which you plan to comply.

(A) You may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:

(1) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current and proposed emission limit;

(2) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(3) Your request demonstrates through performance stack test results completed within 30 days prior to your submission, compliance for each EGU or EGU emissions averaging group with both the mass per heat input and mass per gross output limits;

(4) You revise and submit all other applicable plans, e.g., monitoring and emissions averaging, with your request; and

(5) You maintain records of all information regarding your choice of emission limits.

(B) You begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch.

(C) From submission of your request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, you demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each EGU or EGU emissions averaging group.

(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.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24087, Apr. 24, 2013; 79 FR 68791, Nov. 19, 2014; 81 FR 20187, Apr. 6, 2016]

§63.10031 What reports must I submit and when?

(a) You must submit each report in Table 8 to this subpart that applies to you. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also submit the electronic reports required under appendix A and/or appendix B to the subpart, at the specified frequency.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 8 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.9984.

(2) The first compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.9984.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (9) of this section.

(1) The information required by the summary report located in 63.10(e)(3)(vi).

(2) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(3) Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.

(4) Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in §63.10021(e)(6) and (7) were completed.

(5) Should you choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for your EGU, for each instance of startup or shutdown you shall:

(i) Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of §63.10032(f).

(ii) Include the information required to be monitored, collected, or recorded according to the requirements of §63.10020(e).

(iii) If you choose to use CEMS to demonstrate compliance with numerical limits, include hourly average CEMS values and hourly average flow values during startup periods or shutdown periods. Use units of milligrams per cubic meter for PM CEMS values, micrograms per cubic meter for Hg CEMS values, and ppmv for HCl, HF, or SO₂ CEMS values. Use units of standard cubic meters per hour on a wet basis for flow values.

(iv) If you choose to use a separate sorbent trap measurement system for startup or shutdown reporting periods, include hourly average mercury concentration values in terms of micrograms per cubic meter.

(v) If you choose to use a PM CPMS, include hourly average operating parameter values in terms of the operating limit, as well as the operating parameter to PM correlation equation.

(6) You must report emergency bypass information annually from EGUs with LEE status.

(7) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If you are conducting stack tests once every 3 years to maintain LEE status, consistent with §63.10006(b), the date of each stack test conducted during the previous 3 years, a comparison of emission level you achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in §63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(8) A certification.

(9) If you have a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation.

(d) For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in §63.10(e)(3)(v) in the compliance report specified in section (c).

(e) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) On or after April 16, 2017, within 60 days after the date of completing each performance test, you must submit the performance test reports required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see <http://www.epa.gov/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.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 79 FR 68791, Nov. 19, 2014; 79 FR 68799, Nov. 19, 2014; 80 FR 15514, Mar. 24, 2015; 81 FR 20188, Apr. 6, 2016]

§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.

[77 FR 9464, Feb. 16, 2012, as amended at 79 FR 68792, Nov. 19, 2014; 81 FR 20189, Apr. 6, 2016]

§63.10033 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§63.10040 What parts of the General Provisions apply to me?

Table 9 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§63.10041 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; moreover, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate, with respect to any failure by any person to comply with any provision of this subpart.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in §63.9991(a) and (b) under §63.6(g).

(2) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90, approval of minor and intermediate changes to monitoring performance specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of "test method" in §63.2).

(3) Approval of major changes to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major change to recordkeeping and reporting under §63.10(e) and as defined in §63.90.

§63.10042 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in §63.2 (the General Provisions), and in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Anthracite coal means solid fossil fuel classified as anthracite coal by American Society of Testing and Materials (ASTM) Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see §63.14).

Bituminous coal means coal that is classified as bituminous according to ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see §63.14).

Boiler operating day means a 24-hour period that begins at midnight and ends the following midnight during which any fuel is combusted at any time in the EGU, excluding startup periods or shutdown periods. It is not necessary for the fuel to be combusted the entire 24-hour period.

Capacity factor for a liquid oil-fired EGU means the total annual heat input from oil divided by the product of maximum hourly heat input for the EGU, regardless of fuel, multiplied by 8,760 hours.

Clean fuel means natural gas, synthetic natural gas that meets the specification necessary for that gas to be transported on a Federal Energy Regulatory Commission (FERC) regulated pipeline, propane, distillate oil, synthesis gas that has been processed through a gas clean-up train such that it could be used in a system's combustion turbine, or ultra-low-sulfur diesel (ULSD) oil, including those fuels meeting the requirements of 40 CFR part 80, subpart I ("Subpart I—Motor Vehicle Diesel Fuel; Nonroad, Locomotive, and Marine Diesel Fuel; and ECA Marine Fuel").

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see §63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered "coal" for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns coal for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendar years on an annual rolling basis.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Cogeneration means a steam-generating unit that simultaneously produces both electrical and useful thermal (or mechanical) energy from the same primary energy source.

Cogeneration unit means a stationary, fossil fuel-fired EGU meeting the definition of "fossil fuel-fired" or stationary, integrated gasification combined cycle:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combined-cycle gas stationary combustion turbine means a stationary combustion turbine system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

Common stack means the exhaust of emissions from two or more affected units through a single flue.

Continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located in the continental United States.

Default electrical load means an electrical load equal to 5 percent of the maximum sustainable electrical output (megawatts), as defined in section 6.5.2.1(a)(1) of Appendix A to part 75 of this chapter, of an affected EGU that is in startup or shutdown mode. For monitored common stack configurations, the default electrical load is 5 percent of the combined maximum sustainable electrical load of the EGUs that are in startup or shutdown mode during an hour in which the electrical load for all operating EGUs is zero. The default electrical load is used to calculate the electrical output-based emission rate (lb/MWh or lb/GWh, as applicable) for any startup or shutdown hour in which the actual electrical load is zero. The default electrical load is not used for EGUs required to make heat input-based emission rate (lb/MMBtu or lb/TBtu, as applicable) calculations. For the purposes of this subpart, the default electrical load is not considered to be a substitute data value.

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

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

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

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Diluent cap means a default CO₂ or O₂ concentration that may be used to calculate the Hg, HCl, HF, or SO₂ emission rate (lb/MMBtu or lb/TBtu, as applicable) during a startup or shutdown hour in which the measured CO₂ concentration is below the cap value or the measured O₂ concentration is above the cap value. The appropriate diluent cap values for EGUs are presented in §63.10007(f) and in section 6.2.1.2 of Appendix A to this subpart. For the purposes of this subpart, the diluent cap is not considered to be a substitute data value.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396-10, "Standard Specification for Fuel Oils" (incorporated by reference, see §63.14).

Dry flue gas desulfurization technology, or dry FGD, or spray dryer absorber (SDA), or spray dryer, or dry scrubber means an add-on air pollution control system located downstream of the steam generating unit that injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO₂ and HCl in the exhaust stream forming a dry powder material. Alkaline sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

Dry sorbent injection (DSI) means an add-on air pollution control system in which sorbent (e.g., conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas stream upstream of a PM control device to react with and neutralize acid gases (such as SO₂ and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

Electric Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included) for the purpose of powering a generator to produce electricity or electricity and other thermal energy.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Emission limitation means any emissions limit, work practice standard, or operating limit.

Excess emissions means, with respect to this subpart, results of any required measurements outside the applicable range (e.g., emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60, 61, and 63; requirements within any applicable state implementation plan; and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Flue gas desulfurization system means any add-on air pollution control system located downstream of the steam generating unit whose purpose or effect is to remove at least 50 percent of the SO₂ in the exhaust gas stream.

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

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of producing more than 25 MW of electrical output from the combustion of fossil fuels. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendar years on an annual rolling basis.

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

Fluidized bed boiler, or fluidized bed combustor, or circulating fluidized boiler, or CFB means a boiler utilizing a fluidized bed combustion process.

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

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas.

Generator means a device that produces electricity.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical output, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in an EGU (synthetic gas for an IGCC) and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

Integrated gasification combined cycle electric utility steam generating unit or IGCC means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years in a combined-cycle gas turbine. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. No solid coal or solid oil-derived fuel is directly burned in the unit during operation. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendar years on an annual rolling basis.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite coal means coal that is classified as lignite A or B according to ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see §63.14).

Limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor when burning oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing on the first of the month following the compliance date specified in §63.9984.

Liquid fuel includes, but is not limited to, distillate oil and residual oil.

Monitoring system malfunction or out of control period means any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Neural network or neural net for purposes of this rule means an automated boiler optimization system. A neural network typically has the ability to process data from many inputs to develop, remember, update, and enable algorithms for efficient boiler operation.

Non-continental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Non-continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located outside the continental United States.

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se).

Oil means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (e.g., petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs 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/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 $\geq 8,300$ Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU in the "unit designed for low rank virgin coal" subcategory.

Unit designed for low rank virgin coal subcategory means any coal-fired EGU that is designed to burn and that is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed to burn solid oil-derived fuel subcategory means any oil-fired EGU that burns solid oil-derived fuel.

Voluntary consensus standards or VCS mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. states, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g., Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within an EPA rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-VCS methods.

Wet flue gas desulfurization technology, or wet FGD, or wet scrubber means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO₂ and HCl.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to CAA section 112(h).

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23405, Apr. 19, 2012; 78 FR 24087, Apr. 24, 2013; 79 FR 68792, Nov. 19, 2014; 81 FR 20189, Apr. 6, 2016]

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

As stated in §63.9991, you must comply with the following applicable emission limits:

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM)	9.0E-2 lb/MWh ¹	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	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 ² or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO ₂) ³	1.0 lb/MWh	SO ₂ CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal	a. Filterable particulate matter (PM)	9.0E-2 lb/MWh ¹	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run For ASTM D6348-03 ² or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO ₂) ³	1.0 lb/MWh	SO ₂ CEMS.
	c. Mercury (Hg)	4.0E-2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM)	7.0E-2 lb/MWh ⁴ 9.0E-2 lb/MWh ⁵	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E-2 lb/GWh	
	Arsenic (As)	2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	
	Chromium (Cr)	4.0E-2 lb/GWh	
	Cobalt (Co)	4.0E-3 lb/GWh	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Lead (Pb)	9.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	7.0E-2 lb/GWh	
	Selenium (Se)	3.0E-1 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26 at appendix A-8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348-03 ² or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO ₂) ³	4.0E-1 lb/MWh	SO ₂ CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-1 lb/MWh ¹	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E-4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E-2 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	5.0E-4 lb/GWh	
	Cadmium (Cd)	2.0E-4 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-2 lb/GWh	
	Lead (Pb)	8.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	9.0E-2 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	1.0E-4 lb/GWh	For Method 30B at appendix A-8 to part 60 of this chapter sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 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 . . .
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 ² or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 ² 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)	2.0E-1 lb/MWh ¹	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	6.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-1 lb/GWh	
	Lead (Pb)	3.0E-2 lb/GWh	
	Manganese (Mn)	1.0E-1 lb/GWh	
	Nickel (Ni)	4.1E0 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	4.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/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 ² or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	5.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 ² or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM)	3.0E-2 lb/MWh ¹	Collect a minimum of 1 dscm per run.
	OR	OR	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Total non-Hg HAP metals	6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	7.0E-4 lb/GWh	
	Chromium (Cr)	6.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	7.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	6.0E-3 lb/GWh	
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 ² or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO ₂) ³	1.0 lb/MWh	SO ₂ CEMS.
	c. Mercury (Hg)	2.0E-3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

¹ Gross output.

² Incorporated by reference, see §63.14.

³ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO₂ CEMS installed.

⁴ Duct burners on syngas; gross output.

⁵ Duct burners on natural gas; gross output.

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

As stated in §63.9991, you must comply with the following applicable emission limits:¹

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh ²	Collect a minimum of 1 dscm per run.
	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	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh	For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 ³ or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO ₂) ⁴	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO ₂ CEMS.

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	
		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/MWh ²	Collect a minimum of 1 dscm per run.
	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	
	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	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26 at appendix A-8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348-03 ³ or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO ₂) ⁴	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO ₂ CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM)	4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh ²	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E-2 lb/GWh	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-1 lb/TBtu or 1.0E-3 lb/GWh	
	Cadmium (Cd)	1.5E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E-2 lb/GWh	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	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 ³ or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
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/MWh ²	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 . . .
	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 ³ or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MMBtu or 4.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 ³ 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/MWh ²	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E-4 lb/MMBtu or 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 < 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 . . .
	b. Hydrogen chloride (HCl)	2.0E-4 lb/MMBtu or 2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 ³ or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E-5 lb/MMBtu or 5.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 ³ or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM)	8.0E-3 lb/MMBtu or 9.0E-2 lb/MWh ²	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-5 lb/MMBtu or 6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 7.0E-3 lb/GWh	
	Arsenic (As)	3.0E-1 lb/TBtu or 5.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-2 lb/TBtu or 5.0E-4 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 4.0E-3 lb/GWh	
	Chromium (Cr)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Lead (Pb)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E-2 lb/GWh	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E-1 lb/GWh	
	Selenium (Se)	1.2E0 lb/Tbtu or 2.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	5.0E-3 lb/MMBtu or 8.0E-2 lb/MWh	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 ³ or Method 320, sample for a minimum of 1 hour.
	OR		

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Sulfur dioxide (SO ₂) ⁴	3.0E-1 lb/MMBtu or 2.0E0 lb/MWh	SO ₂ CEMS.
	c. Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

¹For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.

²Gross output.

³Incorporated by reference, see §63.14.

⁴You may not use the alternate 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:

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in §63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in §63.10021(e).
3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup	<p>a. You have the option of complying using either of the following work practice standards:</p> <p>(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).</p>

If your EGU is . . .	You must meet the following . . .
	(2) If you choose to comply using paragraph (2) of the definition of “startup” in §63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup.
	For startup of an EGU, you must use one or a combination of the clean fuels defined in §63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in §63.10020(e).
	Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits beginning with the hour after startup ends. You must engage and operate your particulate matter control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel.
	You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart that require operation of the control devices.
	b. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.
	c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods.
	d. You must collect monitoring data during startup periods, as specified in §63.10020(a) and (e). You must keep records during startup periods, as provided in §§63.10032 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.
4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown	You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart and that require operation of the control devices.
	If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in §63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.
	Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.

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 UUUUU of Part 63—Operating Limits for EGUs

As stated in §63.9991, you must comply with the applicable operating limits:

If you demonstrate compliance using . . .	You must meet these operating limits . . .
PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of §63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

[81 FR 20197, Apr. 6, 2016]

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

As stated in §63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:¹

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using . . .²
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. ³
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using . . . ²
		e. Measure the filterable PM concentration	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).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).
	OR	OR	
	PM CEMS	a. Install, certify, operate, and maintain the PM CEMS	Performance Specification 11 at appendix B to part 60 of this chapter and Procedure 2 at appendix F to part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. ³
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the 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	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.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using . . . ²
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. ³
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the 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 ³ with (1) the following conditions when using ASTM D6348-03: (A) The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory;
			(B) For ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);
	(C) For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% ≥ R ≤ 130%; and		

3.e.1(D) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} \times 100$$

and

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)
			(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.

To conduct a performance test for the following pollutant . . . (cont'd)	Using . . . (cont'd)	You must perform the following activities, as applicable to your input- or output-based emission limit . . . (cont'd)	Using . . . ² (cont'd)
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).
	OR	OR	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. ³
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter, ASTM D6784, ³ or Method 29 at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).
	OR	OR	
	Hg CEMS	a. Install, certify, operate, and maintain the CEMS	Sections 3.2.1 and 5.1 of appendix A of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §63.10010(a), (b), (c), and (d).

To conduct a performance test for the following pollutant . . . (cont'd)	Using . . . (cont'd)	You must perform the following activities, as applicable to your input- or output-based emission limit . . . (cont'd)	Using . . . ² (cont'd)
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of appendix A to this subpart.
	OR	OR	
	Sorbent trap monitoring system	a. Install, certify, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of appendix A to this subpart.
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G, or 2H at appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981, ³ or diluent gas monitoring systems certified according to part 75 of this chapter.
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (<i>i.e.</i> , per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).

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 (SO ₂)	SO ₂ CEMS	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and §63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).

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:

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an EGU	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to §63.10010(h)(1)	Establish a site-specific operating limit in units of PM CPMS output signal (e.g., milliamps, mg/acm, or other raw signal)	Data from the PM CPMS and the PM or HAP metals performance tests	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of §63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

[81 FR 20201, Apr. 6, 2016]

Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

As stated in §63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO ₂ , HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality 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.
2. PM CPMS to measure compliance with a parametric operating limit	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.
3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
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	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in §63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown	Operating in accordance with Table 3.

[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:

You must submit a	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in §63.10031(c)(1) through (9); and	Semiannually according to the requirements in §63.10031(b).

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:

Citation	Subject	Applies to subpart UUUUU
§63.1	Applicability	Yes.
§63.2	Definitions	Yes. Additional terms defined in §63.10042.
§63.3	Units and Abbreviations	Yes.
§63.4	Prohibited Activities and Circumvention	Yes.
§63.5	Preconstruction Review and Notification Requirements	Yes.
§63.6(a), (b)(1) through (5), (b)(7), (c), (f)(2) and (3), (h)(2) through (9), (i), (j)	Compliance with Standards and Maintenance Requirements	Yes.
§63.6(e)(1)(i)	General Duty to minimize emissions	No. See §63.10000(b) for general duty requirement.
§63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§63.6(e)(3)	SSM Plan requirements	No.
§63.6(f)(1)	SSM exemption	No.
§63.6(h)(1)	SSM exemption	No.

Citation	Subject	Applies to subpart UUUUU
§63.6(g)	Compliance with Standards and Maintenance Requirements, Use of an alternative non-opacity emission standard	Yes. See §§63.10011(g)(4) and 63.10021(h)(4) for additional requirements.
§63.7(e)(1)	Performance testing	No. See §63.10007.
§63.8	Monitoring Requirements	Yes.
§63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See §63.10000(b) for general duty requirement.
§63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§63.9	Notification Requirements	Yes, except (1) for the 60-day notification prior to conducting a performance test in §63.9(e); instead use a 30-day notification period per §63.10030(d), (2) the notification of the CMS performance evaluation in §63.9(g)(1) is limited to RATAs, and (3) the information required per §63.9(h)(2)(i); instead provide the information required per §63.10030(e)(1) through (e)(6) and (e)(8).
§63.10(a), (b)(1), (c), (d)(1) and (2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under §63.10(e)(3)(v).
§63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns	No.
§63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See §63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§63.10(b)(2)(iii)	Maintenance records	Yes.
§63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM	No.
§63.10(b)(2)(v)	Actions taken to minimize emissions during SSM	No.
§63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§63.10(b)(2)(vii) through (ix)	Other CMS requirements	Yes.
§63.10(b)(3) and (d)(3) through (5)		No.
§63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions	Yes.

Citation	Subject	Applies to subpart UUUUU
§63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions	Yes.
§63.10(c)(10)	Recording nature and cause of malfunctions	No. See §63.10032(g) and (h) for malfunctions recordkeeping requirements.
§63.10(c)(11)	Recording corrective actions	No. See §63.10032(g) and (h) for malfunctions recordkeeping requirements.
§63.10(c)(15)	Use of SSM Plan	No.
§63.10(d)(5)	SSM reports	No. See §63.10021(h) and (i) for malfunction reporting requirements.
§63.11	Control Device Requirements	No.
§63.12	State Authority and Delegation	Yes.
§§63.13 through 63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§§63.1(a)(5),(a)(7) through (9), (b)(2), (c)(3) and (4), (d), 63.6(b)(6), (c)(3) and (4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2) through (4), (c)(9).	Reserved	No.

[81 FR 20202, Apr. 6, 2016]

Appendix A to Subpart UUUUU of Part 63—Hg Monitoring Provisions

1. General Provisions

1.1 *Applicability.* These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (e.g., lb/TBtu or lb/GWh), regardless of speciation.

1.2 *Initial Certification and Recertification Procedures.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

1.3 *Quality Assurance and Quality Control Requirements.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.

1.4 *Missing Data Procedures.* The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which quality-assured Hg concentration data are not obtained is counted as an hour of monitoring system downtime.

2. Monitoring of Hg Emissions

2.1 *Monitoring System Installation Requirements.* Flue gases from the affected units under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, §63.10010(a) specifies the appropriate location(s) at which to install continuous monitoring systems (CMS). These CMS installation provisions apply to the Hg CEMS, sorbent trap monitoring systems, and other continuous monitoring systems that provide data for the Hg emissions calculations in section 6.2 of this appendix.

2.2 *Primary and Backup Monitoring Systems.* In the electronic monitoring plan described in section 7.1.1.2.1 of this appendix, you must designate a primary Hg CEMS or sorbent trap monitoring system. The primary system must be used to report hourly Hg concentration values when the system is able to provide quality-assured data, *i.e.*, when the system is “in control”. However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate backup monitoring systems, as follows:

2.2.1 *Redundant Backup Systems.* A redundant backup monitoring system may be either a separate Hg CEMS with its own probe, sample interface, and analyzer, or a separate sorbent trap monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location, and is kept on “hot standby” in case the primary monitoring system is unable to provide quality-assured data. A redundant backup system must be represented as a unique monitoring system in the electronic monitoring plan. Each redundant backup monitoring system must be certified according to the applicable provisions in section 4 of this appendix and must meet the applicable on-going QA requirements in section 5 of this appendix.

2.2.2 *Non-redundant Backup Monitoring Systems.* A non-redundant backup monitoring system is a separate Hg CEMS or sorbent trap system that has been certified at a particular unit or stack location, but is not permanently installed at that location. Rather, the system is kept on “cold standby” and may be reinstalled in the event of a primary monitoring system outage. A non-redundant backup monitoring system must be represented as a unique monitoring system in the electronic monitoring plan. Non-redundant backup Hg CEMS must complete the same certification tests as the primary monitoring system, with one exception. The 7-day calibration error test is not required for a non-redundant backup Hg CEMS. Except as otherwise provided in section 2.2.4.5 of this appendix, a non-redundant backup monitoring system may only be used for 720 hours per year at a particular unit or stack location.

2.2.3 *Temporary Like-kind Replacement Analyzers.* When a primary Hg analyzer needs repair or maintenance, you may temporarily install a like-kind replacement analyzer, to minimize data loss. Except as otherwise provided in section 2.2.4.5 of this appendix, a temporary like-kind replacement analyzer may only be used for 720 hours per year at a particular unit or stack location. The analyzer must be represented as a component of the primary Hg CEMS, and must be assigned a 3-character component ID number, beginning with the prefix “LK”.

2.2.4 *Quality Assurance Requirements for Non-redundant Backup Monitoring Systems and Temporary Like-kind Replacement Analyzers.* To quality-assure the data from non-redundant backup Hg monitoring systems and temporary like-kind replacement Hg analyzers, the following provisions apply:

2.2.4.1 When a certified non-redundant backup sorbent trap monitoring system is brought into service, you must follow the procedures for routine day-to-day operation of the system, in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

2.2.4.2 When a certified non-redundant backup Hg CEMS or a temporary like-kind replacement Hg analyzer is brought into service, a calibration error test and a linearity check must be performed and passed. A single point system integrity check is also required, unless a NIST-traceable source of oxidized Hg was used for the calibration error test.

2.2.4.3 Each non-redundant backup Hg CEMS or temporary like-kind replacement Hg analyzer shall comply with all required daily, weekly, and quarterly quality-assurance test requirements in section 5 of this appendix, for as long as the system or analyzer remains in service.

2.2.4.4 For the routine, on-going quality-assurance of a non-redundant backup Hg monitoring system, a relative accuracy test audit (RATA) must be performed and passed at least once every 8 calendar quarters at the unit or stack location(s) where the system will be used.

2.2.4.5 To use a non-redundant backup Hg monitoring system or a temporary like-kind replacement analyzer for more than 720 hours per year at a particular unit or stack location, a RATA must first be performed and passed at that location.

3. Mercury Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (*i.e.*, sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg (Hg^0 , CAS Number 7439-97-6) and oxidized forms of Hg.

3.1 Definitions.

3.1.1 *Mercury Continuous Emission Monitoring System or Hg CEMS* means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include the following major subsystems: sample acquisition, Hg^{+2} to Hg^0 converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS). Hg CEMS may be nominally real-time or time-integrated, batch sampling systems that sample the gas on an intermittent basis and concentrate on a collection medium before intermittent analysis and reporting.

3.1.2 *Sorbent Trap Monitoring System* means the equipment required to monitor Hg emissions continuously by using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a constant proportional rate relative to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter ($\mu\text{g}/\text{dscm}$), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 *NIST* means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 *NIST-Traceable Elemental Hg Standards* means either: compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards"; or calibration gases having known concentrations of elemental Hg, produced by a generator that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators" or an interim version of that protocol.

3.1.5 *NIST-Traceable Source of Oxidized Hg* means a generator that is capable of providing known concentrations of vapor phase mercuric chloride (HgCl_2), and that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators" or an interim version of that protocol.

3.1.6 *Calibration Gas* means a NIST-traceable gas standard containing a known concentration of elemental or oxidized Hg that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 *Span Value* means a conservatively high estimate of the Hg concentrations to be measured by a CEMS. The span value of a Hg CEMS should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate (see section 3.2.1.4.2 of this appendix).

3.1.8 *Zero-Level Gas* means calibration gas containing a Hg concentration that is below the level detectable by the Hg gas analyzer in use.

3.1.9 *Low-Level Gas* means calibration gas with a concentration that is 20 to 30 percent of the span value.

3.1.10 *Mid-Level Gas* means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 *High-Level Gas* means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 *Calibration Error Test* means a test designed to assess the ability of a Hg CEMS to measure the concentrations of calibration gases accurately. A zero-level gas and an upscale gas are required for this test. For the upscale gas, either a mid-level gas or a high-level gas may be used, and the gas may either be an elemental or oxidized Hg standard.

3.1.13 *Linearity Check* means a test designed to determine whether the response of a Hg analyzer is linear across its measurement range. Three elemental Hg calibration gas standards (*i.e.*, low, mid, and high-level gases) are required for this test.

3.1.14 *System Integrity Check* means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 *Cycle Time Test* means a test designed to measure the amount of time it takes for a Hg CEMS, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. The high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 *Relative Accuracy Test Audit or RATA* means a series of nine or more test runs, directly comparing readings from a Hg CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 *Unit Operating Hour* means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 *Stack Operating Hour* means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 *Operating Day* means a calendar day in which a source combusts any fuel.

3.1.20 *Quality Assurance (QA) Operating Quarter* means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 *Grace Period* means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 *Continuous Monitoring Methods.*

3.2.1 *Hg CEMS.* A typical Hg CEMS is shown in Figure A-1. The CEMS in Figure A-1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.

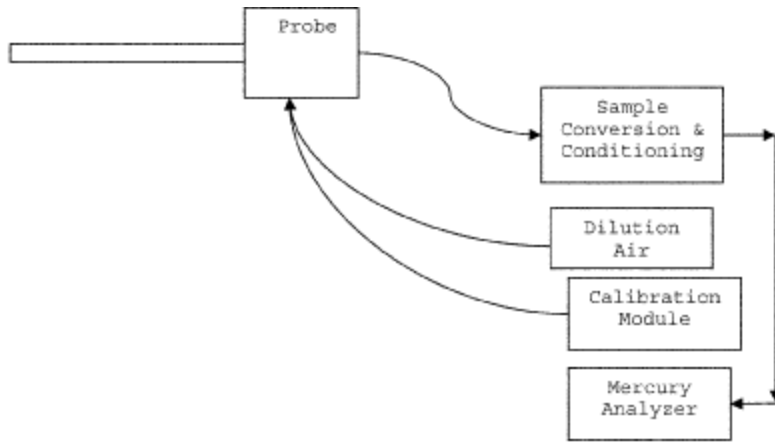


FIGURE A-1. TYPICAL MERCURY CEMS

3.2.1.1 *Equipment Specifications.*

3.2.1.1.1 *Materials of Construction.* All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon™, quartz, and treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 *Temperature Considerations.* All system components prior to the Hg⁺² to Hg⁰ converter must be maintained at a sample temperature above the acid gas dew point.

3.2.1.1.3 *Measurement System Components.*

3.2.1.1.3.1 *Sample Probe.* The probe must be made of the appropriate materials as noted in paragraph 3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 *Filter or Other Particulate Removal Device.* The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 *Sample Line.* The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 *Conditioning Equipment.* For wet basis systems, such as the one shown in Figure A-1, the sample must be kept above its dew point either by: heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

3.2.1.1.3.5 *Sampling Pump.* A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A-1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump must be constructed of any material that is non-reactive to the gas being sampled.

3.2.1.1.3.6 *Calibration Gas System(s)*. Design and equip each Hg CEMS to permit the introduction of known concentrations of elemental Hg and HgCl₂ separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

3.2.1.1.3.7 *Sample Gas Delivery*. The sample line may feed directly to either a converter, a by-pass valve (for Hg speciating systems), or a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

3.2.1.1.3.8 *Hg Analyzer*. An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

3.2.1.1.3.9 *Data Recorder*. A recorder, such as a computerized data acquisition and handling system (DAHS), digital recorder, or data logger, is required for recording measurement data.

3.2.1.2 *Reagents and Standards*.

3.2.1.2.1 *NIST Traceability*. Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this appendix), and including, but not limited to, Hg gas generators and Hg gas cylinders, shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of 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 H_g CEMS

For this required certification test . . .	The main performance specification ¹ is . . .	The alternate performance specification ¹ is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test ²⁶	$ R - A \leq 5.0\%$ of span value, for both the zero and upscale gases, on each of the 7 days.	$ R - A \leq 1.0 \mu\text{g}/\text{scm}$	The alternate specification may be used on any day of the test.
Linearity check ³⁶	$ R - A_{\text{avg}} \leq 10.0\%$ of the reference gas concentration at each calibration gas level (low, mid, or high).	$ R - A_{\text{avg}} \leq 0.8 \mu\text{g}/\text{scm}$	The alternate specification may be used at any gas level.
3-level system integrity check ⁴	$ R - A_{\text{avg}} \leq 10.0\%$ of the reference gas concentration at each calibration gas level.	$ R - A_{\text{avg}} \leq 0.8 \mu\text{g}/\text{scm}$	The alternate specification may be used at any gas level.
RATA	20.0% RA	$ RM_{\text{avg}} - C_{\text{avg}} + CC \leq 0.5 \mu\text{g}/\text{scm}$	$RM_{\text{avg}} < 2.5 \mu\text{g}/\text{scm}$

For this required certification test . . .	The main performance specification ¹ is . . .	The alternate performance specification ¹ is . . .	And the conditions of the alternate specification are . . .
Cycle time test ⁵	15 minutes where the stability criteria are readings change by < 2.0% of span or by ≤ 0.5 µg/scm, for 2 minutes.		

¹Note 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.

²Use elemental Hg standards; a mid-level or high-level upscale gas may be used.

³Use elemental Hg standards.

⁴Use oxidized Hg standards.

⁵Use 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.

⁶If 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.

⁷Note that |RM_{avg} – C_{avg}| is the absolute difference between the mean reference method value and the mean CEMS value from the RATA; CC is the confidence coefficient from Equation 2-5 of Performance Specification 2 in appendix B to part 60 of this chapter.

4.1.1.4 *Cycle Time Test.* Perform the cycle time test, using a zero-level gas and a high-level calibration gas.

Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages—upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading of stack emissions or calibration gas has been attained—the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 µg/scm (whichever is less restrictive) for two minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Integrated batch sampling type Hg CEMS are exempted from this test; however, these systems must be capable of delivering a measured Hg concentration reading at least once every 15 minutes. If necessary to increase measurement sensitivity of a batch sampling type Hg CEMS for a specific application, you may petition the Administrator for approval of a time longer than 15 minutes between readings.

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784-02 (Reapproved 2008), “Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)” (incorporated by reference, see §63.14) and Methods 29, 30A, and 30B in appendix A-8 to part 60 of this chapter. When Method 29 or ASTM D6784-02 is used, paired sampling trains are required and the filterable portion of the sample need not be included when making comparisons to the Hg CEMS results for purposes of a RATA. To validate a Method 29 or ASTM D6784-02 test run, calculate the relative deviation (RD) using Equation A-1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{|C_a - C_b|}{C_a + C_b} \times 100 \quad (Eq. A - 1)$$

Where:

RD = Relative Deviation between the Hg concentrations of samples “a” and “b” (percent),

C_a = Hg concentration of Hg sample “a” (µg/dscm), and

C_b = Hg concentration of Hg sample “b” (µg/dscm).

4.1.1.5.1 *Special Considerations.* A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. More than nine test runs may be performed. If this option is chosen, the results from a maximum of three test runs may be rejected so long as the total number of test results used to determine the relative accuracy is greater than or equal to nine; however, all data must be reported including the rejected data. The minimum time per run is 21 minutes if Method 30A is used. If Method 29, Method 30B, or ASTM D6784-02 (Reapproved 2008), “Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)” (incorporated by reference, see §63.14) is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when Method 29 or ASTM D6784-02 is used, in which case up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2) including the option to substitute the emission limit value (in this case the equivalent concentration) in the denominator of Equation 2-6 in place of the average RM value when the average emissions for the test are less than 50 percent of the applicable emissions limit. For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A-1 of this appendix.

4.1.1.5.3 *Bias Adjustment.* Measurement or adjustment of Hg CEMS data for bias is not required.

4.1.2 *Sorbent Trap Monitoring Systems.* For the initial certification of a sorbent trap monitoring system, only a RATA is required.

4.1.2.1 *Reference Methods.* The acceptable reference methods for the RATA of a sorbent trap monitoring system are the same as those listed in paragraph 4.1.1.5 of this section.

4.1.2.2 “The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap monitoring system. During the RATA, the monitoring system must be operated and quality-assured in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter with the following exceptions for sorbent trap section 2 breakthrough:

4.1.2.2.1 For stack Hg concentrations >1 µg/dscm, ≤10% of section 1 Hg mass;

4.1.2.2.2 For stack Hg concentrations ≤1 µg/dscm and >0.5 µg/dscm, ≤20% of section 1 Hg mass;

4.1.2.2.3 For stack Hg concentrations ≤0.5 µg/dscm and >0.1 µg/dscm, ≤50% of section 1 Hg mass; and

4.1.2.2.4 For stack Hg concentrations ≤0.1µg/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

4.1.2.3 The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.4 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the sorbent trap monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2). For purposes of calculating the relative accuracy, ensure that the

reference method and monitoring system data are on a consistent moisture basis, either wet or dry. The main and alternative RATA performance specifications in Table A-1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.5 *Bias Adjustment.* Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 *Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems.* Monitoring systems that are used to measure stack gas volumetric flow rate, diluent gas concentration, or stack gas moisture content, either for routine operation of a sorbent trap monitoring system or to convert Hg concentration data to units of the applicable emission limit, must be certified in accordance with the applicable provisions of part 75 of this chapter.

4.2 *Recertification.* Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS or sorbent trap monitoring system that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. ONGOING QUALITY ASSURANCE (QA) AND DATA VALIDATION

5.1 Hg CEMS.

5.1.1 *Required QA Tests.* Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A-2, below. All tests must be performed with the affected unit(s) operating (*i.e.*, combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the tests. For each test, follow the same basic procedures in section 4.1.1 of this appendix that were used for initial certification.

5.1.2 *Test Frequency.* The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use a NIST-traceable elemental Hg gas standard for these calibrations. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level, and high-level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are allowed for "non-QA operating quarters". A maximum of three consecutive exemptions for this reason are permitted, following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system integrity checks.

5.1.2.3 Perform a single-level system integrity check weekly, *i.e.*, once every 7 operating days (see the third column in Table A-2 of this appendix).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, *i.e.*, once every four QA operating quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one calendar quarter. However, there is a limit to these extensions; the deadline may not be extended beyond the end of the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the eighth calendar quarter or in a 720 hour unit or stack operating hour grace period following that quarter. When a

required annual RATA is done within a grace period, the deadline for the next RATA is three QA operating quarters after the quarter in which the grace period test is performed.

5.1.3 *Grace Periods.*

5.1.3.1 A 168 unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.3.2 A 720 unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.3.3 There is no grace period for weekly system integrity checks. The test must be completed once every 7 operating days.

5.1.4 *Data Validation.* The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any one of the acceptance criteria for the required QA tests in Table A-2 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.1.5 *Conditional Data Validation.* For certification, recertification, and diagnostic testing of Hg monitoring systems, and for the required QA tests when non-redundant backup Hg monitoring systems or temporary like-kind Hg analyzers are brought into service, the conditional data validation provisions in §§75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete 7-day calibration error tests, linearity checks, cycle time tests, and RATAs shall be as specified in §75.20(b)(3)(iv) of this chapter. Required system integrity checks must be completed within 168 unit or stack operating hours after the probationary calibration error test.

Table A-2—On-Going QA Test Requirements for H_g CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test ⁵	Daily	<ul style="list-style-type: none"> Use either a mid- or high-level gas Use elemental Hg Calibrations are not required when the unit is not in operation. 	$ R - A \leq 5.0\%$ of span value or $ R - A \leq 1.0 \mu\text{g}/\text{scm}$.
Single-level system integrity check	Weekly ¹	<ul style="list-style-type: none"> Use oxidized Hg—either mid- or high-level 	$ R - A_{\text{avg}} \leq 10.0\%$ of the reference gas value or $ R - A_{\text{avg}} \leq 0.8 \mu\text{g}/\text{scm}$.
Linearity check or 3-level system integrity check	Quarterly ³	<ul style="list-style-type: none"> Required in each “QA operating quarter”² and no less than once every 4 calendar quarters 168 operating hour grace period available Use elemental Hg for linearity check Use oxidized Hg for system integrity check 	$ R - A_{\text{avg}} \leq 10.0\%$ of the reference gas value, at each calibration gas level or $ R - A_{\text{avg}} \leq 0.8 \mu\text{g}/\text{scm}$.
RATA	Annual ⁴	<ul style="list-style-type: none"> Test deadline may be extended for “non-QA operating quarters,” up to a maximum of 8 quarters from the quarter of the previous test. 720 operating hour grace period available 	$\leq 20.0\%$ RA when $C_{\text{avg}} \geq 2.5 \mu\text{g}/\text{scm}$ or $ RM_{\text{avg}} - C_{\text{avg}} + CC \leq 0.5 \mu\text{g}/\text{scm}$, if $RM_{\text{avg}} < 2.5 \mu\text{g}/\text{scm}$.

¹“Weekly” means once every 7 operating days.

²A “QA operating quarter” is a calendar quarter with at least 168 unit or stack operating hours.

³“Quarterly” means once every QA operating quarter.

⁴“Annual” means once every four QA operating quarters.

⁵If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors.

5.1.6 *Adjustment of Span.* If you discover that a span adjustment is needed (e.g., if the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter), you must implement the span adjustment within 90 days after the end of the calendar quarter in which you identify the need for the adjustment. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

5.2 *Sorbent Trap Monitoring Systems.*

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B-1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 15 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, *i.e.*, once every four QA operating quarters. The provisions in section 5.1.2.4 of this appendix pertaining to RATA deadline extensions also apply to sorbent trap monitoring systems.

5.2.2.2 The same RATA performance criteria specified in Table A-2 for Hg CEMS also apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.3 A 720 unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.3 Data validation for sorbent trap monitoring systems shall be done in accordance with Table 12B-1 in Performance Specification (PS) 12B in appendix B to part 60 of this chapter. All periods of invalid data shall be counted as hours of monitoring system downtime.

5.3 *Flow Rate, Diluent Gas, and Moisture Monitoring Systems.* The on-going QA test requirements for these monitoring systems are specified in part 75 of this chapter (see §§63.10010(b) through (d)).

5.4 *QA/QC Program Requirements.* The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the Hg CEMS and/or sorbent trap monitoring systems that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the diluent gas, flow rate, and moisture monitoring systems described in section 3.2.1.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

5.4.1 *General Requirements.*

5.4.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the Hg CEMS and/or sorbent trap monitoring system(s) in proper operating condition and a schedule for those procedures. Include, at a minimum, all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.4.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

5.4.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any Hg CEMS or sorbent trap monitoring system in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded (e.g., changing the dilution ratio of a CEMS), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

5.4.2 *Specific Requirements for Hg CEMS.*

5.4.2.1 *Daily Calibrations, Linearity Checks and System Integrity Checks.* Keep a written record of the procedures used for daily calibrations of the Hg CEMS. If moisture and/or chlorine is added to the Hg calibration gas, document how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for in an appropriate manner. Also keep records of the procedures used to perform linearity checks of the Hg CEMS and the procedures for system integrity checks of the Hg CEMS. Document how the test results are calculated and evaluated.

5.4.2.2 *Monitoring System Adjustments.* Document how each component of the Hg CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

5.4.2.3 *Relative Accuracy Test Audits.* Keep a written record of procedures used for RATAs of the Hg CEMS. Indicate the reference methods used and document how the test results are calculated and evaluated.

5.4.3 *Specific Requirements for Sorbent Trap Monitoring Systems.*

5.4.3.1 *Sorbent Trap Identification and Tracking.* Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for chain of custody purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 *Monitoring System Integrity and Data Quality.* Document the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also Document the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B-1 in section 9.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (e.g., wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 *Hg Analysis.* Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter.

5.4.3.4 *Data Collection Period.* State, and provide the rationale for, the minimum acceptable data collection period (e.g., one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Address such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 *Relative Accuracy Test Audit Procedures.* Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

6. DATA REDUCTION AND CALCULATIONS

6.1 Data Reduction.

6.1.1 Reduce the data from Hg CEMS to hourly averages, in accordance with §60.13(h)(2) of this chapter.

6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used in the emissions calculations (*i.e.*, flow rate, diluent gas concentration, or moisture, as applicable), do not calculate the Hg emission rate for that hour. For the purposes of this appendix, part 75 substitute data values are not considered to be valid data.

6.1.4 Operating hours in which valid data are not obtained for Hg concentration are considered to be hours of monitor downtime. The use of substitute data for Hg concentration is not required.

6.2 *Calculation of Hg Emission Rates.* Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 *Heat Input-Based Hg Emission Rates.* Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu, according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in appendix A-7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg concentration value by 6.24×10^{-11} to convert it from $\mu\text{g}/\text{scm}$ to lb/scf. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Also, for startup and shutdown hours, you may calculate the Hg emission rate using the applicable diluent cap value specified in section 3.3.4.1 of appendix F to part 75 of this chapter, provided that the diluent gas monitor is not out-of-control and the hourly average O_2 concentration is above 14.0% O_2 (19.0% for an IGCC) or the hourly average CO_2 concentration is below 5.0% CO_2 (1.0% for an IGCC), as applicable.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by 10^6 to convert it to lb/TBtu.

6.2.1.4 The heat input-based Hg emission rate limit in Table 2 to this subpart must be met on a 30 boiler operating day rolling average basis, except as otherwise provided in §63.10009(a)(2). Use Equation 19-19 in EPA Method 19 to calculate the Hg emission rate for each averaging period. The term E_{hj} in Equation 19-19 must be in the units of the applicable emission limit. Do not include non-operating hours with zero emissions in the average.

6.2.2 *Electrical Output-Based Hg Emission Rates.* Calculate electrical output-based Hg emission limits in units of lb/GWh, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 Calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters, using Equation A-2 of this section (for wet-basis measurements of Hg concentration) or Equation A-3 of this section (for dry-basis measurements), as applicable:

$$M_h = K C_h Q_h \quad (\text{Equation A-2})$$

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/ μg -scf,

C_h = Hourly average Hg concentration, wet basis ($\mu\text{g}/\text{scm}$)

Q_h = Stack gas volumetric flow rate for the hour (scfh).

(NOTE: Use unadjusted flow rate values; bias adjustment is not required)

$$M_h = K C_h Q_h (1 - B_{ws}) \quad (\text{Equation A-3})$$

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/ μg -scf.

C_h = Hourly average Hg concentration, dry basis ($\mu\text{g}/\text{dscm}$).

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 % $\text{H}_2\text{O}/100$)

6.2.2.2 Use Equation A-4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

$$E_{ho} = \frac{M_h}{(MW)_h} \times 10^3 \quad (\text{Equation A-4})$$

Where:

E_{ho} = Electrical output-based Hg emission rate (lb/GWh).

M_h = Hg mass emission rate for the hour, from Equation A-2 or A-3 of this section, as applicable (lb/h).

$(MW)_h$ = Gross electrical load for the hour, in megawatts (MW).

10^3 = Conversion factor from megawatts to gigawatts.

6.2.2.3 The applicable gross output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30- (or 90-) boiler operating day rolling average basis, except as otherwise provided in §63.10009(a)(2). Use Equation A-5 of this appendix to calculate the Hg emission rate for each averaging period.

$$\bar{E}_o = \frac{\sum_{h=1}^n E_{ho}}{n} \quad (\text{Eq. A-5})$$

Where:

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 ($\mu\text{g}/\text{scm}$, 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 ($\mu\text{g}/\text{scm}$, 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.

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Appendix B to Subpart UUUUU of Part 63—HCl and HF Monitoring Provisions

1. Applicability

These monitoring provisions apply to the measurement of HCl and/or HF emissions from electric utility steam generating units, using CEMS. The CEMS must be capable of measuring HCl and/or HF in the appropriate units of the applicable emissions standard (*e.g.*, lb/MMBtu, lb/MWh, or lb/GWh).

2. Monitoring of HCl and/or HF Emissions

2.1 Monitoring System Installation Requirements. Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with §63.10010(a) and either Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems or Performance Specification 18 (PS 18) of appendix B to part 60 of this chapter for HCl CEMS.

2.2 *Primary and Backup Monitoring Systems.* The provisions pertaining to primary and redundant backup monitoring systems in section 2.2 of appendix A to this subpart apply to HCl and HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit.

2.3 *FTIR Monitoring System Equipment, Supplies, Definitions, and General Operation.* The following provisions apply:

2.3.1 PS 15, Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 of appendix B to part 60 of this chapter; or

2.3.2 PS 18, Sections 3.0, 6.0, and 11.0 of appendix B to part 60 of this chapter.

3. Initial Certification Procedures

The initial certification procedures for the HCl or HF CEMS used to provide data under this subpart are as follows:

3.1 If you choose to follow PS 15 of appendix B to part 60 of this chapter, then your HCl and/or HF CEMS must be certified according to PS 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below.

3.1.1 You must conduct a gas audit of the HCl and/or HF CEMS as described in section 9.1 of Performance Specification 15, with the exceptions listed in sections 3.1.2.1 and 3.1.2.2 below.

3.1.1.1 The audit sample gas does not have to be obtained from the Administrator; however, it must be (1) from a secondary source of certified gases (*i.e.*, independent of any calibration gas used for the daily calibration assessments) and (2) directly traceable to National Institute of Standards and Technology (NIST) or VSL Dutch Metrology Institute (VSL) reference materials through an unbroken chain of comparisons. If audit gas traceable to NIST or VSL reference materials is not available, you may use a gas with a concentration certified to a specified uncertainty by the gas manufacturer.

3.1.1.2 Analyze the results of the gas audit using the calculations in section 12.1 of Performance Specification 15. The calculated correction factor (CF) from Eq. 6 of Performance Specification 15 must be between 0.85 and 1.15. You do not have to test the bias for statistical significance.

3.1.2 You must perform a relative accuracy test audit or RATA according to section 11.1.1.4 of Performance Specification 15 and the requirements below. Perform the RATA of the HCl or HF CEMS at normal load. Acceptable HCl/HF reference methods (RM) are Methods 26 and 26A in appendix A-8 to part 60 of this chapter, Method 320 in Appendix A to this part, or ASTM D6348-03 (Reapproved 2010) "Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy" (incorporated by reference, see §63.14), each applied based on the criteria set forth in Table 5 of this subpart.

3.1.2.1 When ASTM D6348-03 is used as the RM, the following conditions must be met:

3.1.2.1.1 The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory;

3.1.2.1.2 In ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);

3.1.2.1.3 For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be $70\% \leq R \leq 130\%$; and

3.1.2.1.4 The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} \times 100 \quad (\text{Eq. B-1})$$

3.1.2.2 The relative accuracy (RA) of the HCl or HF CEMS must be no greater than 20 percent of the mean value of the RM test data in units of ppm on the same moisture basis. Alternatively, if the mean RM value is less than 1.0 ppm, the RA results are acceptable if the absolute value of the difference between the mean RM and CEMS values does not exceed 0.20 ppm.

3.2 If you choose to follow PS 18 of appendix B to part 60 of this chapter, then your HCl CEMS must be certified according to PS 18, sections 7.0, 8.0, 11.0, 12.0, and 13.0.

3.3 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

4. Recertification Procedures

Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: Replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. On-Going Quality Assurance Requirements

On-going QA test requirements for HCl and HF CEMS must be implemented as follows:

5.1 If you choose to follow Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures of PS 15 shall apply as set forth in sections 5.1.1 through 5.1.3 and 5.4.2 of this appendix.

5.1.1 On a daily basis, you must assess the calibration error of the HCl or HF CEMS using either a calibration transfer standard as specified in Performance Specification 15 Section 10.1 which references Section 4.5 of the FTIR Protocol or a HCl and/or HF calibration gas at a concentration no greater than two times the level corresponding to the applicable emission limit. A calibration transfer standard is a substitute calibration compound chosen to ensure that the FTIR is performing well at the wavelength regions used for analysis of the target analytes. The measured concentration of the calibration transfer standard or HCl and/or HF calibration gas results must agree within ± 5 percent of the reference gas value after correction for differences in pressure.

5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, "quarterly" means once every "QA operating quarter" (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for "non-QA operating quarters" (*i.e.*, calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.4.2.2.1 of this appendix.

5.1.3 You must perform an annual relative accuracy test audit or RATA of the HCl or HF CEMS as described in section 3.1.2 of this appendix. Perform the RATA at normal load. For the purposes of this appendix, "annual" means once every four "QA operating quarters" (as defined in section 3.1.20 of appendix A to this subpart). The first annual RATA is due within four QA operating quarters following the calendar quarter in which the initial certification testing of the HCl or HF CEMS is successfully completed. The provisions in section 5.1.2.4 of appendix A to this subpart pertaining to RATA deadline extensions also apply.

5.2 If you choose to follow Performance Specification PS 18 of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures in Procedure 6 of appendix F to part 60 of this chapter shall apply. The quarterly

and annual QA tests required under Procedure 6 shall be performed, respectively, at the frequencies specified in sections 5.1.2 and 5.1.3 of this appendix.

5.3 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

5.3.1 *Out-of-Control Periods.* A HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.3.2 *Grace Periods.* For the purposes of this appendix, a “grace period” is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.3.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.2 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.3.2.2 For the purposes of this appendix, if the deadline for a required gas audit or RATA of a HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.3.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit; or

5.3.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.3.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.3.2.3.1 For a gas audit or RATA of the monitoring systems described in section 5.1 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.3.2.3.2 For the gas audit of a HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit is required for that quarter.

5.3.2.3.3 For the RATA of a HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.3.3 *Conditional Data Validation* For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in §§75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in §75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit shall be the same as for a linearity check (*i.e.*, 168 unit or stack operating hours).

5.4 *Data Validation.*

5.4.1 *Out-of-Control Periods.* An HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was

either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.4.2 *Grace Periods.* For the purposes of this appendix, a “grace period” is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.4.2.1 For the monitoring systems described in section 5.3 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.4.2.2 For the purposes of this appendix, if the deadline for a required gas audit/data accuracy assessment or RATA of an HCl CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.4.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit or other quarterly data accuracy assessment; or

5.4.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.4.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.4.2.3.1 For a gas audit or RATA of the monitoring systems described in sections 5.1 and 5.2 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.4.2.3.2 For the gas audit or other quarterly data accuracy assessment of an HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit/data accuracy assessment is required for that quarter.

5.4.2.3.3 For the RATA of an HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.4.3 *Conditional Data Validation.* For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, the conditional data validation provisions in §75.20(b)(3)(ii) through (ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in §75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a quarterly gas audit or data accuracy assessment shall be the same as for a linearity check (*i.e.*, 168 unit or stack operating hours).

6. Missing Data Requirements

For the purposes of this appendix, the owner or operator of an affected unit shall not substitute for missing data from HCl or HF CEMS. Any process operating hour for which quality-assured HCl or HF concentration data are not obtained is counted as an hour of monitoring system downtime.

7. Bias Adjustment

Bias adjustment of hourly emissions data from a HCl or HF CEMS is not required.

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that

the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

8.1 *General Requirements for HCl and HF CEMS.*

8.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the HCl and/or HF CEMS in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

8.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

8.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any HCl or HF CEMS in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: Date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded and a written explanation of the procedures used to make the adjustment(s) shall be kept.

8.2 *Specific Requirements for HCl and HF CEMS.* The following requirements are specific to HCl and HF CEMS:

8.2.1 Keep a written record of the procedures used for each type of QA test required for each HCl and HF CEMS. Explain how the results of each type of QA test are calculated and evaluated.

8.2.2 Explain how each component of the HCl and/or HF CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

9. Data Reduction and Calculations

9.1 Design and operate the HCl and/or HF CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

9.2 Reduce the HCl and/or HF concentration data to hourly averages in accordance with §60.13(h)(2) of this chapter.

9.3 Convert each hourly average HCl or HF concentration to an HCl or HF emission rate expressed in units of the applicable emissions limit.

9.3.1 For heat input-based emission rates, select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in Appendix A-7 to part 60 of this chapter, to calculate the HCl or HF emission rate in lb/MMBtu. Multiply the HCl concentration value (ppm) by 9.43×10^{-8} to convert it to lb/scf, for use in the applicable Method 19 equation. For HF, the conversion constant from ppm to lb/scf is 5.18×10^{-8} . The appropriate diluent cap value from section 6.2.1.2 of Appendix A to this subpart may be used to calculate the HCl or HF emission rate (lb/MMBtu) during startup or shutdown hours.

9.3.2 For gross output-based emission rates, first calculate the HCl or HF mass emission rate (lb/h), using an equation that has the general form of Equation A-2 or A-3 in appendix A to this subpart (as applicable), replacing the value of K with 9.43×10^{-8} lb/scf-ppm (for HCl) or 5.18×10^{-8} (for HF) and defining C_h as the hourly average HCl or HF concentration in ppm. Then, divide the result by the hourly gross output (megawatts) to convert it to units of lb/MWh. If the gross output is zero during a startup or shutdown hour, use the default gross output (as defined in §63.10042) to calculate the HCl or HF emission rate. The default gross output is not considered to be a substitute data value.

9.4 Use Equation A-5 in appendix A of this subpart to calculate the required 30 operating day rolling average HCl or HF emission rates. Round off each 30 operating day average to two significant figures. The term E_{ho} in Equation A-5 must be in the units of the applicable emissions limit.

10. Recordkeeping Requirements

10.1 For each HCl or HF CEMS installed at an affected source, and for any other monitoring system(s) needed to convert pollutant concentrations to units of the applicable emissions limit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with §63.10033. The file shall contain the information in paragraphs 10.1.1 through 10.1.8 of this section.

10.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the HCl and/or HF CEMS and any other monitoring system(s) (i.e., flow rate, diluent gas, or moisture systems) needed to convert pollutant concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall explain how the data derived from these systems ensure that all HCl or HF emissions from the unit or stack are monitored and reported.

10.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous HCl or HF monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

10.1.1.2 *Contents of the Monitoring Plan.* For HCl and/or HF CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under §75.53 (g) of this chapter. The electronic monitoring plan shall be evaluated using the ECMPS Client Tool.

10.1.1.2.1 *Electronic.* Record the unit or stack ID number(s); monitoring location(s); the HCl or HF monitoring methodology used (i.e., CEMS); HCl or HF monitoring system information, including, but not limited to: unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; monitor span and range information (if applicable).

10.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations (if applicable); miscellaneous technical justifications.

10.1.2 *Operating Parameter Records.* For the purposes of this appendix, the owner or operator shall record the following information for each operating hour of each affected unit or group of units utilizing a common stack, to the extent that these data are needed to convert pollutant concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 10.1.2.1 and 10.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 10.1.2.1, 10.1.2.2, and (if applicable) 10.1.2.4 of this section.

10.1.2.1 The date and hour;

10.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

10.1.2.3 The hourly gross unit load (rounded to nearest MWge); and

10.1.2.4 If applicable, the F-factor used to calculate the heat input-based pollutant emission rate.

10.1.2.5 If applicable, a flag to indicate that the hour is a startup or shutdown hour (as defined in §63.10042).

10.1.3 *HCl and/or HF Emissions Records.* For HCl and/or HF CEMS, the owner or operator must record the following information for each unit or stack operating hour:

10.1.3.1 The date and hour;

10.1.3.2 Monitoring system and component identification codes, as provided in the electronic monitoring plan, for each hour in which the CEMS provides a quality-assured value of HCl or HF concentration (as applicable);

10.1.3.3 The pollutant concentration, for each hour in which a quality-assured value is obtained. For HCl and HF, record the data in parts per million (ppm), rounded to three significant figures.

10.1.3.4 A special code, indicating whether or not a quality-assured HCl or HF concentration value is obtained for the hour. This code may be entered manually when a temporary like-kind replacement HCl or HF analyzer is used for reporting; and

10.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to §75.32 of this chapter.

10.1.4 *Stack Gas Volumetric Flow Rate Records.*

10.1.4.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required to demonstrate compliance with electrical output-based HCl or HF emissions limits (*i.e.*, lb/MWh or lb/GWh).

10.1.4.2 Use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in §75.57(c)(2) of this chapter.

10.1.5 *Records of Stack Gas Moisture Content.*

10.1.5.1 Correction of hourly pollutant concentration data for moisture is sometimes required when converting concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

10.1.5.1.1 To calculate electrical output-based pollutant emission rates, when using a CEMS that measures pollutant concentrations on a dry basis; and

10.1.5.1.2 To calculate heat input-based pollutant emission rates, when using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter.

10.1.5.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage for coal-fired units from §75.11(b)(1) of this chapter, an Administrator approved default moisture value for non-coal-fired units (as per paragraph 63.10010(d) of this subpart), or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you elect to use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in §75.57(c)(3) of this chapter.

10.1.6 *Records of Diluent Gas (CO₂ or O₂) Concentration.*

10.1.6.1 To assess compliance with a heat input-based HCl or HF emission rate limit in units of lb/MMBtu, hourly measurements of CO₂ or O₂ concentration are required to convert pollutant concentrations to units of the standard.

10.1.6.2 If hourly measurements of diluent gas concentration are needed, you must use a certified CO₂ or O₂ monitor that meets the requirements of part 75 of this chapter to record the required data. For all diluent gas monitors, you must keep hourly CO₂ or O₂ concentration records, as specified in §75.57(g) of this chapter.

10.1.7 *HCl and HF Emission Rate Records.* For applicable HCl and HF emission limits in units of lb/MMBtu, lb/MWh, or lb/GWh, record the following information for each affected unit or common stack:

10.1.7.1 The date and hour;

10.1.7.2 The hourly HCl and/or HF emissions rate (lb/MMBtu, lb/MWh, or lb/GWh, as applicable, rounded to three significant figures), for each hour in which valid values of HCl or HF concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

10.1.7.3 An identification code for the formula used to derive the hourly HCl or HF emission rate from HCl or HF concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

10.1.7.4 A code indicating that the HCl or HF emission rate was not calculated for the hour, if valid data for HCl or HF concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

10.1.7.5 If applicable, a code to indicate that the default electrical load (as defined in §63.10042) was used to calculate the HCl or HF emission rate.

10.1.7.6 If applicable, a code to indicate that the diluent cap (as defined in §63.10042) was used to calculate the HCl or HF emission rate.

10.1.8 *Certification and Quality Assurance Test Records.* For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 *HCl and HF CEMS.*

10.1.8.1.1 For all required daily calibrations (including calibration transfer standard tests) of the HCl or HF CEMS, record the test dates and times, reference values, monitor responses, and calculated calibration error values;

10.1.8.1.2 For gas audits of HCl or HF CEMS, record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of Performance Specification 15, and the results of those calculations and analyses.

10.1.8.1.3 For each RATA of a HCl or HF CEMS, record the date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS values. Keep records of the data analyses and calculations used to determine the relative accuracy.

10.1.8.2 *Additional Monitoring Systems.* For the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2 of this appendix, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in §75.59(a) of this chapter.

11. Reporting Requirements

11.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting HCl and/or HF emissions from each affected unit (or group of units monitored at a common stack):

11.1.1 Notifications, in accordance with paragraph 11.2 of this section;

11.1.2 Monitoring plan reporting, in accordance with paragraph 11.3 of this section;

11.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 11.4 of this section; and

11.1.4 Electronic quarterly report submittals, in accordance with paragraph 11.5 of this section.

11.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) in accordance with §63.10030.

11.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) using HCl and/or HF CEMS, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

11.3.1 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 ECMP5 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 ECMP5 Client Tool to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically, either prior to or concurrent with the relevant quarterly electronic emissions report.

11.4.1 For daily calibrations (including calibration transfer standard tests), report the information in §75.59(a)(1) of this chapter, excluding paragraphs (a)(1)(ix) through (a)(1)(xi).

11.4.2 For each quarterly gas audit of a HCl or HF CEMS, report:

11.4.2.1 Facility ID information;

11.4.2.2 Monitoring system ID number;

11.4.2.3 Type of test (e.g., quarterly gas audit);

11.4.2.4 Reason for test;

11.4.2.5 Certified audit (spike) gas concentration value (ppm);

11.4.2.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.2.7 Calculated dilution ratio for audit (spike) gas;

11.4.2.8 Date and time of each spiked flue gas sample;

11.4.2.9 Date and time of each unspiked flue gas sample;

11.4.2.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.2.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of Performance Specification 15 (ppm);

11.4.2.12 Bias at the spike level as calculated using equation 3 in section 12.1 of Performance Specification 15; and

11.4.2.13 The correction factor (CF), calculated using equation 6 in section 12.1 of Performance Specification 15.

11.4.3 For each RATA of a HCl or HF CEMS, report:

- 11.4.3.1 Facility ID information;
- 11.4.3.2 Monitoring system ID number;
- 11.4.3.3 Type of test (*i.e.*, initial or annual RATA);
- 11.4.3.4 Reason for test;
- 11.4.3.5 The reference method used;
- 11.4.3.6 Starting and ending date and time for each test run;
- 11.4.3.7 Units of measure;
- 11.4.3.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;
- 11.4.3.9 Flags to indicate which test runs were used in the calculations;
- 11.4.3.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;
- 11.4.3.11 Standard deviation, as specified in Equation 2-4 of Performance Specification 2 in appendix B to part 60 of this chapter;
- 11.4.3.12 Confidence coefficient, as specified in Equation 2-5 of Performance Specification 2 in appendix B to part 60 of this chapter; and
- 11.4.3.13 Relative accuracy calculated using Equation 2-6 of Performance Specification 2 in appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in section 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

11.4.4 *Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.* For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.9.3 of this appendix.

11.5 *Quarterly Reports.*

11.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in §63.10005(g), (h), or (j) (whichever is earlier), the owner or operator of any affected unit shall use the ECMPs Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack).

11.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

11.5.3 Each electronic quarterly report shall include the following information:

- 11.5.3.1 The date of report generation;
- 11.5.3.2 Facility identification information;

11.5.3.3 The information in sections 10.1.2 through 10.1.7 of this appendix, as applicable to the type(s) of monitoring system(s) used to measure the pollutant concentrations and other necessary parameters.

11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests) of the HCl or HF monitor as described in section 10.1.8.1.1 of this appendix; and

11.5.3.5 If applicable, the results of all daily flow monitor interference checks, in accordance with section 10.1.8.2 of this appendix.

11.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all HCl and/or HF emissions from the affected unit(s) have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24094, Apr. 24, 2013; 79 FR 68795, Nov. 19, 2014; 81 FR 20205, Apr. 6, 2016]

**Indiana Department of Environmental Management
Office of Air Quality**

Technical Support Document (TSD) for Significant Permit Modification to a
Part 70 Operating Permit

Source Description and Location
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Source Name:	Duke Energy Indiana, LLC - Gibson Generating Station
Source Location:	1097 N 950 W, Owensville, Indiana 47665
County:	Gibson
SIC Code:	4911 (Electric Services)
Operation Permit No.:	051-33624-00013
Operation Permit Issuance Date:	January 16, 2014
Significant Permit Modification No.:	051-36994-00013
Permit Reviewer:	Vasantha Palakurti

Existing Approvals

The source was issued Part 70 operating permit (Renewal) No. T051-33624-00013 on January 16, 2014. The source has since received the following approvals:

- (a) Administrative Amendment No. 051-36763-00013, issued on February 11, 2016 and
- (b) Significant Permit Modification No. 051-34614-00013, issued on October 7, 2014.

County Attainment Status

The source is located in Gibson County

Pollutant	Designation
SO ₂	Cannot be classified.
CO	Unclassifiable or attainment effective November 15, 1990.
O ₃	Unclassifiable or attainment effective July 20, 2012, for the 2008 8-hour ozone standard. ¹
PM _{2.5}	Attainment effective October 27, 2011, for the annual PM _{2.5} standard for Montgomery Township. Unclassifiable or attainment effective April 5, 2005, for the annual PM _{2.5} standard for the remainder of the county.
PM _{2.5}	Unclassifiable or attainment effective December 13, 2009, for the 24-hour PM _{2.5} standard.
PM ₁₀	Unclassifiable effective November 15, 1990.
NO ₂	Cannot be classified or better than national standards.
Pb	Unclassifiable or attainment effective December 31, 2011.
¹ Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005.	

- (a) **Ozone Standards**
Volatile organic compounds (VOC) and Nitrogen Oxides (NO_x) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NO_x emissions are considered when evaluating the rule applicability relating to ozone. County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NO_x emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

- (b) **PM_{2.5}**
 Gibson County has been classified as attainment for PM_{2.5}. Therefore, direct PM_{2.5}, SO₂, and NO_x emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.
- (c) **Other Criteria Pollutants**
 Gibson County has been classified as attainment or unclassifiable in Indiana for all other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

Since this source is classified as a power plant, it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, and 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Source Status - Existing Source

The table below summarizes the potential to emit of the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

Process / Emission Unit	Source-Wide Emissions Before Modification (ton/year)								
	PM	PM ₁₀	PM _{2.5}	SO ₂	NO _x	VOC	CO	Single HAP*	Combine d HAPs
Total for Source	18,368	5,072	4,894	293,076	70,525	436	3,747	>10	>25
PSD Major Source Thresholds	100	100	100	100	100	100	100	--	--

*Single highest source-wide HAP.

On June 23, 2014, in the case of *Utility Air Regulatory Group v. EPA*, cause no. 12-1146, (available at http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA's guidance states that U.S. EPA will no longer require PSD or Title V permits for sources "previously classified as 'Major' based solely on greenhouse gas emissions."

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHGs emissions to determine operating permit applicability or PSD applicability to a source or modification.

- (a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a PSD regulated pollutant is emitted at a rate of 100 tons per year or more, and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).
- (b) These emissions are based upon Title V operating permit no. 051-33624-00013, issued on January 16, 2014.

- (c) This existing source is a major source of HAPs, as defined in 40 CFR 63.2, because HAP emissions are greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).

Description of Proposed Amendment

The Office of Air Quality (OAQ) received an application submitted by Duke Energy Indiana, LLC - Gibson Generating on March 23, 2016, requesting to strike the term "(whichever is later)" everywhere it is used in regards to the Unit 5 PM CEMS thereby making the PM CEMS the current compliance method for PM and opacity and addition of compliance extension requirements for unit 5 pertaining to 40 CFR Part 63, Subpart UUUUU.

Enforcement Issues

There are no pending enforcement actions related to this amendment.

Emission Calculations

There is no change in emissions calculations.

Permit Level Determination – Part 70 Modification to an Existing Source

There is no increase in the potential to emit of any regulated pollutants associated with this modification. This modification is not subject to the source modification requirements under 326 IAC 2-7-10.5. The changes will be incorporated into the permit a Significant Permit Modification under 326 IAC 2-7-12, because the modification requires addition of compliance extension requirements for unit 5 pertaining to 40 CFR Part 63, Subpart UUUUU in the existing Part 70 permit.

Additionally, the modification will be incorporated into the Part 70 Operating Permit through a significant permit modification issued pursuant to 326 IAC 2-7-12(d)(1), because the modification incorporates applicable portions of the National Emission Standards for Hazardous Air Pollutants: Coal - and Oil - Fired Electric Utility Steam Generating Units, 40 CFR 63, Subpart UUUUU.

Permit Level Determination – PSD

This modification does not cause any emission increase. Therefore, the requirements of 326 IAC 2-2 (PSD) are not applicable.

Federal Rule Applicability Determination

The following federal rules are applicable to the source due to this modification:

- (a) This modification does not involve any new emission units or modified emission units, therefore, no CAM (40 CFR 64) requirements are included in the permit.

NSPS:

- (b) There are no New Source Performance Standards (NSPS)(326 IAC 12 and 40 CFR Part 60) applicable to this proposed modification.

NESHAP:

- (c) This source is subject to National Emission Standards for Hazardous Air Pollutants: Coal - and Oil - Fired Electric Utility Steam Generating Units, 40 CFR 63, Subpart UUUUU. The boilers, identified as Boiler no. 1 - Boiler no. 5, are subject to the National Emission Standards for Hazardous Air Pollutants for Coal and Oil-Fired Electric Utility Steam Generating Units (40 CFR 63, Subpart UUUUU) because each unit is defined (40 CFR

63.10042) as an electric utility steam generating unit (EGU) which combusts fossil fuel in order to serve a generator which produces more than 25 Megawatts of electricity for sale.

The emission units subject to 40 CFR 63, Subpart UUUUU are as follows:

- (1) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (2) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (3) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with a flue gas conditioning system and an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (4) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack D.

Stack D has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x) sulfur dioxide (SO₂) and particulate matter (PM)

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (5) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate

matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack C.

Stack C has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

The Boilers 1 - 5, are subject to the following portions of 40 CFR 63, Subpart UUUUU:

- (1) 40 CFR 63.9981
- (2) 40 CFR 63.9982(a)(1), (d)
- (3) 40 CFR 63.9984(b), (c), (f)
- (4) 40 CFR 63.9990(a)(1), (a)(2)
- (5) 40 CFR 63.9991(a)(1), (a)(2), (b), (c)(1), (c)(2)
- (6) 40 CFR 63.10000(a), (b), (c)(1)(iv); (v), (vi)(B), (d)(1), (d)(2)(i), (d)(2)(ii), (d)(3), (d)(4), (d)(5)(i-vii); (e), (l)
- (7) 40 CFR 63.10005(a), (a)(1), (a)(2)(i-iii); (b)(1-5); (d)(1), (d)(2)(i-iii); (d)(3), (e), (h)(1)(i)-(ii)(A-B); (h)(2)(i-ii); (h)(3)(i)(A-D); (h)(3)(ii); (h)(3)(iii)(A-B); (h)(3)(iii)(C)(1-5); (j), (k)
- (8) 40 CFR 63.10006(b)(1-2); (c), (d), (f), (i), (j)
- (9) 40 CFR 63.10007(a)(1), (a)(2), (b), (d), (e)(1), (e)(2), (f)(1)(ii) and (2); (g)
- (10) 40 CFR 63.10009(a), (b)(1), (b)(2), (d), (e), (f)(1), (g)(1), (h-k), (n)
- (11) 40 CFR 63.10010(a)(2)(ii); (b-e), (a)(4), (c-e), (f)(1-4); (g), (h)(1-7); (i)(1-5); (j)(1-4); (l)(1-5)
- (12) 40 CFR 63.10011(a-g)
- (13) 40 CFR 63.10020(a-d), (e)(1) – (3)(i)(A-D)
- (14) 40 CFR 63.10021(a-c); (d)(1-2); (e-i)
- (15) 40 CFR 63.10022
- (16) 40 CFR 63.10023(a), (b)(1), (c)
- (17) 40 CFR 63.10030(a), (b), (d), (e)
- (18) 40 CFR 63.10031(a-g)
- (19) 40 CFR 63.10032(a), (b), (d)(1)
- (20) 40 CFR 63.10033(a-c)
- (21) 40 CFR 63.10040
- (22) 40 CFR 63.10041(a-b)
- (23) 40 CFR 63.10042
- (24) 40 CFR 63 Appendix A to Subpart UUUUU
- (25) 40 CFR 63 Appendix B to Subpart UUUUU
- (26) 40 CFR 63, Subpart UUUUU, Table 1
- (27) 40 CFR 63, Subpart UUUUU, Table 2, Subcategory 1
- (28) 40 CFR 63, Subpart UUUUU, Table 3, Subcategory 1
- (29) 40 CFR 63, Subpart UUUUU, Table 4, Subcategory 1
- (30) 40 CFR 63, Subpart UUUUU, Table 5, Subcategories 1-5
- (31) 40 CFR 63, Subpart UUUUU, Table 6, Subcategory 1
- (32) 40 CFR 63, Subpart UUUUU, Table 7, Subcategory 1
- (33) 40 CFR 63, Subpart UUUUU, Table 8, Subcategory 1
- (34) 40 CFR 63, Subpart UUUUU, Table 9

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) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) applicable to this proposed amendment.

CAIR

Pursuant to 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a), the source is subject to the provisions of CAIR. Section F of the permit contains the provisions the Permittee must follow.

CSAPR

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 five (5) boilers identified as Boiler 1 - Boiler 5.

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_x Annual Trading Program and TR NO_x Ozone Season Trading Program and TR SO₂ Group 1 Trading Program and TR SO₂ Group 2 Trading Program.

Unit ID: Gibson Station Unit 1					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO ₂ monitoring) and 40 CFR part 75, subpart H (for NO _x monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO ₂	X				
NO _x	X				
Heat input	X				

Unit ID: Gibson Station Unit 2					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO ₂ monitoring) and 40 CFR part 75, subpart H (for NO _x monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO ₂	X				
NO _x	X				
Heat input	X				

Unit ID: Gibson Station Unit 3					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO ₂ monitoring) and 40 CFR part 75, subpart H (for NO _x monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO ₂	X				
NO _x	X				
Heat input	X				

Unit ID: Gibson Station Unit 4					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO ₂ monitoring) and 40 CFR part 75, subpart H (for NO _x monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO ₂	X				
NO _x	X				
Heat input	X				

Unit ID: Gibson Station Unit 5					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO ₂ monitoring) and 40 CFR part 75, subpart H (for NO _x monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO ₂	X				
NO _x	X				
Heat input	X				

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 NO_x Annual Trading Program) and 97.530 through 97.535 (TR NO_x

Ozone Season Trading Program) and 97.630 through 97.635 (TR SO₂ Group 1 Trading Program) and 97.730 through 97.735 (TR SO₂ Group 2 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 NO_x Annual Trading Program) and 97.535 (TR NO_x Ozone Season Trading Program) and 97.635 (TR SO₂ Group 1 Trading Program) and 97.535 (TR SO₂ Group 2 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 NO_x Annual Trading Program) and 97.530 through 97.534 (TR NO_x Ozone Season Trading Program) and 97.630 through 97.634 (TR SO₂ Group 1 Trading Program) and 97.730 through 97.734 (TR SO₂ Group 2 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 NO_x Annual Trading Program) and 97.535 (TR NO_x Ozone Season Trading Program) and 97.635 (TR SO₂ Group 1 Trading Program) and 97.735 (TR SO₂ Group 2 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 NO_x Annual Trading Program) and 97.530 through 97.534 (TR NO_x Ozone Season Trading Program) and 97.630 through 97.634 (TR SO₂ Group 1 Trading Program) and 97.730 through 97.734 (TR SO₂ Group 2 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.

State Rule Applicability Determination

This modification does not involve any new emission unit, or modified emission unit., therefore, no new state rules are included in the permit.

Compliance Determination, Monitoring and Testing Requirements

The existing compliance requirements will not change as a result of this modification. The source shall continue to comply with the applicable requirements and permit conditions as contained in Part 70 Renewal No: T051-34614-00013, issued on October 7, 2016 with its most recent revisions and amendments.

New compliance determination and monitoring requirements applicable per 40 CFR Part 63, Subpart UUUUU are added to Section D.5.15 of the permit as shown in the Proposed Changes section below. Changes to the compliance determination and monitoring requirements are detailed in the Proposed Changes section of this document.

Proposed Changes

The following changes listed below are due to the proposed amendment. Deleted language appears as ~~strikethrough~~ text and new language appears as **bold** text:

Duke Energy requests to strike the term "(whichever is later)" everywhere it is used in regards to the Boilers 1 to 5 PM CEMS thereby making the PM CEMS the current compliance method for PM and opacity. PM CEMS has already been certified and it is the method of compliance with PM limits and opacity. Therefore, revisions to the permit conditions are as following:

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 No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), ~~with a flue gas conditioning system~~ and an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate

matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack D.

~~Stack D Boiler No. 4~~ has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack C.

~~Stack C Boiler No. 5~~ has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) and a Boiler 5 has a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

Change: IDEM, OAQ has clarified further Section C Asbestos Abatement Projects, Emission Statement and General Reporting Requirements to match the current model language

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

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

- (b) The Permittee shall ensure that a written notification is sent on a form provided by the Commissioner at least ten (10) working days before asbestos stripping or removal work or before demolition begins, per 326 IAC 14-10-3, and shall update such notice as necessary, including, but not limited to the following:**
 - (1) When the amount of affected asbestos containing material increases or decreases by at least twenty percent (20%); or**

 - (2) If there is a change in the following:**
 - (A) Asbestos removal or demolition start date;**

 - (B) Removal or demolition contractor; or**

 - (C) Waste disposal site.**

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

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

All required notifications shall be submitted to:

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

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

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

- (f) **Demolition and Renovation**
The Permittee shall thoroughly inspect the affected facility or part of the facility where the demolition or renovation will occur for the presence of asbestos pursuant to 40 CFR 61.145(a).
- (g) **Indiana Licensed Asbestos Inspector**
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Licensed Asbestos Inspector to 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.

C.16 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6-3(b)(2), **starting in 2005 and every three (3) years thereafter**, ~~a)(4)~~, Pursuant to 326 IAC 2-6-3(b)(2), 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:

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

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

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

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

- (1) **Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;**
- (2) **Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and**
- (3) **A description of the actions taken to implement a QIP during the reporting period as specified in Section C-Response to Excursions or Exceedances. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.**

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

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

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

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

...

~~D.1.2D.1.3 Sulfur Dioxide (SO₂) and Pollution Control Project [326 IAC 7-4-12.1][326 IAC 2-2.3]
[326 IAC 2-3.3]~~

...

~~D.1.3D.1.4 Operation Standard [326 IAC 2-1.1-5(a)(4)]**Reserved**~~

...

~~D.1.4D.1.5 Preventive Maintenance Plan [326 IAC 1-6-3]~~

...

~~D.1.5D.1.6 Reserved~~

...

~~D.1.6D.1.7 Operation of Electrostatic Precipitator and Flue gas Desulfurization [326 IAC 2-7-6(6)]~~

...

~~D.1.8 Maintenance of Continuous Opacity Monitoring System [326 IAC 2-7-5(3)(A)(iii)]~~

...

~~D.1.7~~**D.1.9** Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5]
[326 IAC 2-7-5(3)(A)(iii)]

...

- (d) Whenever a continuous emission monitor ~~other than an opacity monitor~~ is malfunctioning or is down for maintenance or repairs, the following shall be used as an alternative to continuous data collection:

...

~~D.1.8~~**D.1.10** Sulfur Dioxide Emissions [326 IAC 7-2][326 IAC 7-4-12.1][326 IAC 2-7-5(3)(A)][326 IAC 2-7-6]

...

Whenever the primary and backup SO₂ continuous emission monitoring systems are malfunctioning or down for repairs or adjustments for less than twenty-four (24) hours, the Permittee shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each

~~D.1.9~~**D.1.11** Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

...

- (d) **In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.**
- (e) **Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5 and Construction Permit PSD (26) 1215.**

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

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

~~(a) Number of recycle pumps in service; and~~

~~(b) Absorber pH.~~

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

...

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

...

~~D.1.10~~**D.1.14** SO₂ Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

...

~~Whenever the primary and backup SO₂ continuous emission monitoring systems are malfunctioning or down for repairs or adjustments for less than twenty-four (24) hours, the Permittee shall substitute an average of the quality assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.~~

D.1.11 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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

- (a) **The ability of the electrostatic precipitator to control particulate matter emissions shall be monitored once per day when Unit 1 is in operation by measuring and recording the following:**
 - (1) **the primary and secondary currents of the T-R sets.**
 - (2) **the primary and secondary voltages of the T-R sets**
 - (3) **daily number of TR sets in service**

D.1.12D.1.15 Record Keeping Requirement

- (a) **To document the compliance status with Conditions D.1.1 - PSD BACT Requirements, D.1.6 - Operation of Electrostatic Precipitator and Flue gas Desulfurization, D.1.98 - Particulate Matter (PM) Continuous Emission Monitoring System and D.1.11 - PM Monitoring System Downtime, the Permittee shall maintain records in accordance with (1) through (2) below.**

Records shall be complete and sufficient to establish compliance with the limits in Condition D.1.1 - PSD BACT Requirements. ~~Maintenance of Continuous Emission Monitoring Equipment for PM, SO₂ and NO_x.~~

- (1) **PM CEMS data to measure PM pursuant to 326 IAC 3-5 and 326 IAC 7-2-1(g).** ~~The Permittee shall record the output of the continuous monitoring systems and shall perform the required record keeping and reporting, pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.~~
- (2) **The Permittee shall maintain the monthly records of the PM, SO₂ and NO_x emissions from the coal-fired boiler, identified as Boiler No. 1 based on the CEM data. All ESP parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.1.11 - PM Monitoring System Downtime.**

- (b) **To document the compliance status with Conditions D.1.2 – Sulfur Dioxide (SO₂) and Pollution Control Project, and Conditions D.1.1 - PSD BACT Requirements, D.1.2 – Temporary Alternative Opacity Limitations, D.1.7 - Continuous Emissions Monitoring for, SO₂ and NO_x, Condition D.1.10 - SO₂ Monitor Downtime, D.1.12 – Transformer-Rectifier (T-R) Sets, and D.1.13 – Opacity Readings, the Permittee shall maintain records in accordance with (1) through (25) below.**

Records shall be complete and sufficient to establish compliance with the limits established in Section C – Opacity and in Conditions D.1.2 – Sulfur Dioxide (SO₂) and Pollution Control Project. ~~D.1.1 - PSD BACT Requirements, D.1.2 – Temporary Alternative Opacity Limitations;~~

- ~~(1) Data and results from the most recent stack test until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
- ~~(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5 until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
- ~~(3) The results of all Method 9 visible emission readings taken during any periods of COM downtime until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
- (1)(4) All SO₂ continuous emissions monitoring data pursuant to 326 IAC 3-5-6, and 326 IAC 7-2-1(g). PM CEMS data after January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).**
- (2)(5) All flue gas desulfurization (FGD) system parametric monitoring readings taken during periods of CEMS down time, in accordance with Condition D.1.10 - SO₂ Monitoring Downtime. All ESP parametric monitoring readings.**
- (3) To document the compliance status with Condition D.1.2, The Permittee shall keep records of the daily average coal sulfur content, coal heat content, weighting factor, and daily average sulfur dioxide emission rate in pounds per MMBtu.**
- (4) To document the compliance status with Condition D.1.2, the Permittee shall keep records of the pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.**
- ~~(c) To document the compliance status with **Condition D.1.1 – PM limits**, Conditions **D.1.2 D.1.3 – Sulfur Dioxide (SO₂) and Pollution Control Project, D.1.9 D.1.10 – Sulfur Dioxide Emissions, and D.1.6(b) D.1.7(b) – Operation of Electrostatic Precipitator and Flue Gas Desulfurization (FGD)**, the Permittee shall maintain all **PM and SO₂** continuous emissions monitoring data, pursuant to 326 IAC 7-2-1(g), with calendar dates and beginning and ending times of any CEM downtime.~~
- (d) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

~~D.1.13-D.1.16~~ Reporting Requirement

- (a) A quarterly report of ~~opacity exceedances~~ shall be submitted not later than thirty (30) days following the end of each calendar quarter ~~until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later)~~. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
...
- (c) ~~After January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later)~~, Permittee shall report any PM exceedances as part of its regular deviation reports.

- (d) To document compliance with Condition D.1.2, the Permittee shall submit quarterly reports of daily average sulfur content, coal heat content, daily average sulfur dioxide emission rate in lbs per MMBtu, and the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per MMBtu shall be submitted to the department in the quarterly report and maintained by the source owner or operator for a period of at least two (2) years.

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

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

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

...
...

~~D.2.2D.2.3 Sulfur Dioxide (SO₂) and Pollution Control Project [326 IAC 7-4-12.1][326 IAC 2-2.3]~~
[326 IAC 2-3.3]

...

~~D.2.3D.2.4 Operation Standard [326 IAC 2-1.1-5(a)(4)] Reserved~~

...

~~D.2.4D.2.5 Preventive Maintenance Plan [326 IAC 1-6-3]~~

...

~~D.2.5D.2.6 Reserved~~

...

~~D.2.6D.2.7 Operation of Electrostatic Precipitator and Flue gas Desulfurization [326 IAC 2-7-6(6)]~~

...

~~D.2.8 Maintenance of Continuous Opacity Monitoring System [326 IAC 2-7-5(3)(A)(iii)]~~

~~D.2.7~~^{...}
~~D.2.9~~ Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5]
[326 IAC 2-7-5(3)(A)(iii)]

- ~~(d)~~ Whenever a continuous emission monitor ~~other than an opacity monitor~~ is malfunctioning or is down for maintenance or repairs, the following shall be used as an alternative to continuous data collection:
- ...

~~D.2.8~~^{...}
~~D.2.10~~ Sulfur Dioxide Emissions [326 IAC 7-2][326 IAC 7-4-12.1][326 IAC 2-7-5(3)(A)][326 IAC 2-7-6]

~~D.2.9~~^{...}
~~D.2.11~~ Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

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

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

- ~~(b)~~ Number of recycle pumps in service; and
~~(b)~~ Absorber pH.

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

- (e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5 and Construction Permit PSD (26) 1215.**

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

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

~~D.2.10~~^{...}
~~D.2.14~~ SO₂ Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

D.2.11 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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

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

- (1) the primary and secondary currents of the T-R sets.
- (2) the primary and secondary voltages of the T-R sets
- (3) daily number of TR sets in service

D.2.12~~D.2.15~~ Record Keeping Requirement

- (a) To document the compliance status with **Conditions D.2.1 - PSD BACT Requirements, D.2.6 - Operation of Electrostatic Precipitator and Flue Desulfurization (FGD), D.2.9 - Particulate Matter (PM) Continuous Emission Monitoring System and D.2.11 - PM Monitoring System Downtime**~~Condition D.2.9 - Maintenance of Continuous Emission Monitoring Equipment for PM, SO₂ and NO_x,~~ the Permittee shall maintain records in accordance with (1) through (2) below.
- (1) ~~The Permittee shall record the output of the continuous monitoring systems and~~ shall perform the required record keeping and reporting, pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7. **PM CEMS data when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit and 326 IAC 3-5.**
 - (2) ~~The Permittee shall maintain the monthly records of the SO₂ and NO_x emissions from the coal fired boiler, identified as Boiler No. 2 based on the CEM data.~~ **All ESP parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.2.11 - PM Monitoring System Downtime**
- (b) To document the compliance status with ~~Section C - Opacity and Condition D.2.2 Sulfur Dioxide (SO₂) and Pollution Control Project, D.2.7 - Continuous Emissions Monitoring for SO₂ and NO_x, Condition D.2.8- Sulfur Dioxide Emissions and Condition D.1.10 SO₂ Monitor Downtime~~ **PSD BACT Requirements, D.2.2- Temporary Alternative Opacity Limitations, D.2.8 - Continuous Emissions Monitoring for PM, SO₂ and NO_x, D.2.12 - Transformer Rectifier (T-R) Sets, and D.2.13 - Opacity Readings,** the Permittee shall maintain records in accordance with (1) through (5) below.

Records shall be complete and sufficient to establish compliance with the limits established in ~~Section C - Opacity and in~~ **SO₂ limits in** Conditions ~~D.2.4 2- PSD BACT Requirements, D.2.2 - Temporary Alternative Opacity Limitations;~~

- ~~(1) Data and results from the most recent stack test until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
- ~~(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5 until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
- ~~(3) The results of all Method 9 visible emission readings taken during any periods of COM downtime until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
- ~~(4)~~**(1) PM CEMS data after January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later). All SO₂ continuous emissions monitoring data pursuant to 326 IAC 3-**

5-6, and 326 IAC 7-2-1(g).

- ~~(5)(2)~~ All ~~ESP parametric monitoring readings.~~ **All flue gas desulfurization (FGD) system parametric monitoring readings taken during periods of CEMS down time, in accordance with Condition D.2.10 - SO₂ Monitoring Downtime.**
- (3) To document the compliance status with Condition D.2.2, The Permittee shall keep records of the daily average coal sulfur content, coal heat content, weighting factor, and daily average sulfur dioxide emission rate in pounds per MMBtu.**
- (4) To document the compliance status with Condition D.2.2, the Permittee shall keep records of the pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.**
- ~~(c) To document the compliance status with **Condition D.2.1 – PM limits**, Conditions **D.2.2 D.2.3 - Sulfur Dioxide (SO₂) and Pollution Control Project, D.2.9 D.2.10 - Sulfur Dioxide Emissions, and D.2.6 D.2.7(b) - Operation of Electrostatic Precipitator and Flue Gas Desulfurization (FGD)**, the Permittee shall maintain all **PM and SO₂** continuous emissions monitoring data, pursuant to 326 IAC 7-2-1(g), with calendar dates and beginning and ending times of any CEM downtime.~~
- (c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.2.13 D.2.16 Reporting Requirement

- ~~(a) A quarterly report of opacity exceedances shall be submitted not later than thirty (30) days following the end of each calendar quarter until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later). The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.~~
- ...
- (c) ~~After January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later),~~ Permittee shall report any PM exceedances as part of its regular deviation reports.
- (d) To document compliance with Condition D.2.2, the Permittee shall submit quarterly reports of daily average sulfur content, coal heat content, daily average sulfur dioxide emission rate in lbs per MMBtu, and the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per MMBtu shall be submitted to the department in the quarterly report and maintained by the source owner or operator for a period of at least two (2) years.**

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), ~~with a flue gas conditioning system and an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control~~

of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

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

~~D.3.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]~~

...
...

~~D.3.2D.3.3 Sulfur Dioxide (SO₂) and Pollution Control Project [326 IAC 7-4-12.1][326 IAC 2-2.3]~~
~~[326 IAC 2-3.3]~~

...

~~D.3.3D.3.4 Operation Standard [326 IAC 2-1.1-5(a)(4)]~~ **Reserved**

...

~~D.3.4D.3.5 Preventive Maintenance Plan [326 IAC 1-6-3]~~

...

~~D.3.5D.3.6 Reserved~~

...

~~D.3.6D.3.7 Operation of Electrostatic Precipitator and Flue gas Desulfurization [326 IAC 2-7-6(6)]~~

...

~~D.3.8 Maintenance of Continuous Opacity Monitoring System [326 IAC 2-7-5(3)(A)(iii)]~~

~~D.3.7D.3.9 Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5]~~
~~[326 IAC 2-7-5(3)(A)(iii)]~~

...

- (d) Whenever a continuous emission monitor ~~other than an opacity~~ is malfunctioning or is down for maintenance or repairs, the following shall be used as an alternative to continuous data collection:

...

~~D.3.8D.3.10 Sulfur Dioxide Emissions [326 IAC 7-2][326 IAC 7-4-12.1][326 IAC 2-7-5(3)(A)][326 IAC 2-7-6]~~

...

~~D.3.9D.3.11 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]~~

...

- (d) ~~Whenever this PM CEMS is malfunctioning or down for repair or adjustments for 24 hours or more, and a backup CEMS is not brought on-line, the following shall be used~~

~~to provide information related to particulate emissions:~~

- (1) ~~The ability of the FGD electrostatic precipitator to control particulate matter emissions shall be monitored once per day when Unit 1 is in operation by measuring and recording the following:~~
- ~~(c) Number of recycle pumps in service; and~~
 - ~~(b) Absorber pH.~~
- (d) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.
- (e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5 and Construction Permit PSD (26) 1215.

~~D.3.12 Transformer Rectifier (T-R) Sets [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]~~

...

~~D.3.13 Opacity Reading [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]~~

...

~~D.3.10D.3.14 SO₂ Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]~~

...

D.3.11 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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

- (a) **The ability of the electrostatic precipitator to control particulate matter emissions shall be monitored once per day when Unit 1 is in operation by measuring and recording the following:**
- (1) the primary and secondary currents of the T-R sets.**
 - (2) the primary and secondary voltages of the T-R sets**
 - (3) daily number of TR sets in service**

~~D.3.12D.3.15 Record Keeping Requirement~~

- (a) To document the compliance status with Section C - Opacity and Conditions D.3.1 - PSD BACT Requirements, **D.3.6 - Operation of Electrostatic Precipitator and Flue Gas Desulfurization (FGD), D.3.9 - Particulate Matter (PM) Continuous Emission Monitoring System and D.3.11 - PM Monitoring System Downtime,**~~D.3.2 - Temporary Alternative Opacity Limitations, D.3.6 D.3.8 - Continuous Emissions Monitoring for PM, SO₂ and NO_x, D.3.12 - Transformer Rectifier (T-R) Sets, and D.3.13 - Opacity Readings,~~ the Permittee shall maintain records in accordance with (1) through (2) below.

Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.3.1 - PSD BACT Requirements, ~~D.3.2 - Temporary Alternative Opacity Limitations;~~

- ~~(1) Data and results from the most recent stack test until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
 - ~~(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5 until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
 - ~~(3) The results of all Method 9 visible emission readings taken during any periods of COM downtime until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
 - (4) (1) PM CEMS data when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit and 326 IAC 3-5. PM CEMS data after January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).**
 - ~~(5) (2) All ESP parametric monitoring readings. All ESP parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.2.11 - PM Monitoring System Downtime.~~
- (b) To document the compliance status with, Conditions ~~D.3.2 D.3.3~~ Sulfur Dioxide (SO₂) and Pollution Control Project, **D.3.7 - Continuous Emissions Monitoring for SO₂ and NO_x, Condition 3.8 - Sulfur Dioxide Emissions, Condition D.3.10 - SO₂ Monitor Downtime** the Permittee shall maintain records in accordance with (1) through (2) below. **Records shall be complete and sufficient to establish compliance with the SO₂ limit established in conditions D.3.2D.3.9 D.3.10 - Sulfur Dioxide Emissions, and D.3.6 D.3.7(b) - Operation of Electrostatic Precipitator and Flue Gas Desulfurization (FGD), the Permittee shall maintain all PM and SO₂ continuous emissions monitoring data, pursuant to 326 IAC 7-2-1(g), with calendar dates and beginning and ending times of any CEM downtime.**
- (1) All SO₂ continuous emissions monitoring data pursuant to 326 IAC 3-5-6, and 326 IAC 7-2-1(g).**
 - (2) All flue gas desulfurization (FGD) system parametric monitoring readings taken during periods of CEMS down time, in accordance with Condition D.3.10 - SO₂ Monitoring Downtime.**
 - (3) To document the compliance status with Condition D.3.2, The Permittee shall keep records of the daily average coal sulfur content, coal heat content, weighting factor, and daily average sulfur dioxide emission rate in pounds per MMBtu.**
 - (4) To document the compliance status with Condition D.3.2, the Permittee shall keep records of the pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.**

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

D.3.13 D.3.16 Reporting Requirement

- (a) A quarterly report of ~~opacity exceedances~~ shall be submitted not later than thirty (30) days following the end of each calendar quarter ~~until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~ The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
...
- (c) ~~After January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later),~~ Permittee shall report any PM exceedances as part of its regular deviation reports.
- (d) **To document compliance with Condition D.3.2, the Permittee shall submit quarterly reports of daily average sulfur content, coal heat content, daily average sulfur dioxide emission rate in lbs per MMBtu, and the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per MMBtu shall be submitted to the department in the quarterly report and maintained by the source owner or operator for a period of at least two (2) years.**

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

<p>Emissions Unit Description:</p> <ul style="list-style-type: none">(d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NOx during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 4D. <p>Stack D Boiler No. 4 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).</p> <p>[This facility is an affected source under 40 CFR 63, Subpart UUUUU]</p> <p>(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)</p>

~~D.4.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]~~

...
...

~~D.4.2D.4.3 Sulfur Dioxide (SO₂) and Pollution Control Project [326 IAC 7-4-12.1][326 IAC 2-2.3]
[326 IAC 2-3.3]~~

...

~~D.4.3D.4.4 Operation Standard [326 IAC 2-1.1-5(a)(4)] **Reserved**~~

...

~~D.4.4~~D.4.5 Preventive Maintenance Plan [326 IAC 1-6-3]

...

~~D.4.5~~D.4.6 Reserved

...

~~D.4.6~~D.4.7 Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]

...

~~D.4.8~~ Maintenance of Continuous Opacity Monitoring System [326 IAC 2-7-5(3)(A)(iii)]

...

~~D.4.8~~ ~~D.4.10~~ Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

...

~~D.4.9~~D.4.11-Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

...

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

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

~~(d) Number of recycle pumps in service; and~~

~~(b) Absorber pH.~~

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

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5 and Construction Permit PSD (26) 1215.

~~D.4.10~~D.4.12 Sulfur Dioxide Emissions [326 IAC 7-2][326 IAC 7-4-12.1][326 IAC 2-7-5(3)(A)][326 IAC 2-7-6]

...

~~D.4.12~~ Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

...

~~D.4.13~~ Opacity Reading [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

...

~~D.4.11~~D.4.14 SO₂ Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

...

D.4.12 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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

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

- (1) the primary and secondary currents of the T-R sets.**
- (2) the primary and secondary voltages of the T-R sets**
- (3) daily number of TR sets in service**

D.4.13 D.4.15 Record Keeping Requirement

(a) To document the compliance status with Section C - Opacity and Conditions D.4.1 - PSD BACT Requirements, **D.4.6 - Operation of Electrostatic Precipitator, D.4.9 - Particulate Matter (PM) Continuous Emission Monitoring System and D.4.12 - PM Monitoring System Downtime** ~~D.4.2 - Temporary Alternative Opacity Limitations, D.4.9 D.4.10 - Continuous Emissions Monitoring for PM, SO₂ and NO_x, D.4.12 - Transformer-Rectifier (T-R) Sets, and D.4.13 - Opacity Readings,~~ the Permittee shall maintain records in accordance with (1) through (2) below.

Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.4.1 - PSD BACT Requirements, ~~D.4.2 - Temporary Alternative Opacity Limitations;~~

- ~~(1) Data and results from the most recent stack test until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
- ~~(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5 until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
- ~~(3) (1) PM CEMS data when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit and 326 IAC 3-5. PM CEMS data after January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
- (4) (2) All ESP parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.4.12 - PM Monitoring System Downtime. All ESP parametric monitoring readings.**

(b) To document the compliance status with SO₂ Conditions **D.4.2** ~~D.4.3 - Sulfur Dioxide (SO₂) Sulfur Limitations, D.4.9 D.4.10 - Continuous Emissions Monitoring for SO₂ and NO_x, D.4.11 - Sulfur Dioxide Emissions, D.4.7 D.4.8 - Flue Gas Desulfurization (FGD) System, and D.4.11 D.4.15 - SO₂ Monitor Downtime,~~ the Permittee shall maintain records in accordance with (1) ~~through~~ **and** (2) below.

Records shall be complete and sufficient to establish compliance with the SO₂ limits as

required in Conditions **D.4.2** ~~D.4.3~~ - Sulfur Dioxide (SO₂), and **D.4.11** ~~D.4.12~~ - Sulfur Dioxide Emissions. The Permittee shall maintain records in accordance with (2) and ~~(3)~~ below during SO₂ CEMS system downtime if a backup CEMS is not used.

- (1) All SO₂ continuous emissions monitoring data, pursuant to 326 IAC 7-2-1(g) and **326 IAC 3-5,**
- (2) All flue gas desulfurization (FGD) system parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.4.15-SO₂ Monitor Downtime.
- ~~(3) Actual fuel usage during each SO₂ CEM downtime.~~
- (3) To document the compliance status with Condition D.4.2, The Permittee shall keep records of the daily average coal sulfur content, coal heat content, weighting factor, and daily average sulfur dioxide emission rate in pounds per MMBtu.**
- (4) To document the compliance status with Condition D.4.2, the Permittee shall keep records of the pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.**

...

D.4.13 ~~D.4.16~~ Reporting Requirement

- (a) A quarterly report of ~~opacity exceedances~~ and a quarterly summary of the information to ~~document the compliance status with Condition D.4.2 - Temporary Alternative Opacity Limitations~~ shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter until ~~January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~ The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
- (b) Pursuant to 326 IAC 3-5-7(5), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:
 - (1) Date of downtime.
 - (2) Time of commencement.
 - (3) Duration of each downtime.
 - (4) Reasons for each downtime.
 - (5) Nature of system repairs and adjustments.

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

- (c) ~~After January 1, 2015 or when the PM CEMS is installed, certified, and operating to~~

~~measure PM pursuant to this permit (whichever is later),~~ Permittee shall report any PM exceedances as part of its regular deviation reports.

- (d) **To document compliance with Condition D.4.2, the Permittee shall submit quarterly reports of daily average sulfur content, coal heat content, daily average sulfur dioxide emission rate in lbs per MMBtu, and the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per MMBtu shall be submitted to the department in the quarterly report and maintained by the source owner or operator for a period of at least two (2) years.**

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack ~~C5~~.

Boiler No. 5 Stack C has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) and ~~Boiler 5 has a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

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

~~D.5.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]~~

...
...

~~D.5.2~~**D.5.3** Sulfur Dioxide (SO₂) and Pollution Control Project [326 IAC 7-4-12.1][326 IAC 2-2.3]
[326 IAC 2-3.3]

...

~~D.5.3~~**D.5.4** Operation Standard [326 IAC 2-1.1-5(a)(4)] **Reserved**

...

~~D.5.4~~**D.5.5** Preventive Maintenance Plan [326 IAC 1-6-3]

...

~~D.5.5~~**D.5.6** Compliance Schedule for National Emission Standard for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units [40 CFR 63, Subpart UUUUU] **Reserved**

...

~~D.5.6~~**D.5.7** Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]

...

~~D.5.7~~**D.5.8** Flue Gas Desulfurization (FGD) System [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

...

~~D.5.8 Maintenance of Continuous Opacity Monitoring System [326 IAC 2-7-5(3)(A)(iii)]~~

...

D.5.8D.5.9 Maintenance of Continuous Emission Monitoring System for SO₂ and NO_x [326 IAC 3-5]
[326 IAC 2-7-5(3)(A)(iii)]

...

D.5.10 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

...

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

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

~~(e) Number of recycle pumps in service; and~~

~~(b) Absorber pH.~~

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

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 26 IAC 3-5 and Construction Permit PSD (26) 1215.

~~D.5.12 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]~~

...

~~D.5.13 Opacity Reading [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]~~

...

D.5.11D.5.14 SO₂ Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

...

Whenever the primary and backup SO₂ continuous emission monitoring systems are malfunctioning or down for repairs or adjustments for less than twenty-four (24) hours, the Permittee shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each

D.5.12 PM Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)][326 IAC 2-7-5(1)]

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

(1) The ability of the electrostatic precipitator to control particulate matter emissions shall be monitored once per day when Unit 1 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
- (c) daily number of TR sets in service

D.5.13D.5.15 Record Keeping Requirement

- (a) To document the compliance status with Section C - Opacity and Conditions D.5.1 - PSD BACT Requirements, ~~D.5.2 - Temporary Alternative Opacity Limitations, D.5.9 D.5.10 - Continuous Emissions Monitoring for PM, SO₂ and NO_x, D.5.12 - Transformer Rectifier (T-R) Sets, and D.5.13 - Opacity Readings~~, the Permittee shall maintain records in accordance with (1) through (5) below.

Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.5.1 - PSD BACT Requirements, ~~D.5.2 - Temporary Alternative Opacity Limitations;~~

- (1) ~~Data and results from the most recent stack test until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
- (2) ~~All continuous opacity monitoring data, pursuant to 326 IAC 3-5 until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
- (3) ~~The results of all Method 9 visible emission readings taken during any periods of COM downtime until January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
- (4) **(1)** PM CEMS data after January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit ~~(whichever is later).~~
- (5) **(2)** All ESP parametric monitoring readings.

- (b) To document the compliance status with SO₂ Conditions **D.5.2** ~~D.5.3 - Sulfur Dioxide (SO₂), D.5.9 D.5.10 - Continuous Emissions Monitoring for SO₂ and NO_x, D.5.10 - Sulfur Dioxide Emissions, D.5.7 D.5.8 - Flue Gas Desulfurization (FGD) System, and D.5.11 D.5.15 - SO₂ Monitor Downtime~~, the Permittee shall maintain records in accordance with (1) through (3) below.

Records shall be complete and sufficient to establish compliance with the SO₂ limits as required in Conditions **D.5.2** ~~D.5.3 - Sulfur Dioxide (SO₂), and D.5.11 D.5.12 - Sulfur Dioxide Emissions~~. The Permittee shall maintain records in accordance with (2) and (3) below during SO₂ CEMS system downtime if a backup CEMS is not used.

- (b) To document the compliance status with Conditions **D.5.2** ~~D.5.3 - Sulfur Dioxide (SO₂), D.5.7 D.5.8 - Flue Gas Desulfurization (FGD) System, D.5.9 D.5.10 - Continuous Emissions Monitoring for SO₂ and NO_x, D.5.11 D.5.12 - Sulfur Dioxide Emissions, and D.5.14 - Opacity Readings~~, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the SO₂ limits as required in Conditions **D.5.2** ~~D.5.3 - Sulfur Dioxide (SO₂), and D.5.7 D.5.8 - Flue Gas Desulfurization (FGD) System~~. The Permittee shall maintain records in accordance with (2) and (3) below during SO₂ CEMS system downtime if a backup

CEMS is not used.

- (1) All SO₂ continuous emissions monitoring data, pursuant to 326 IAC 7-2-1(g) and 40 CFR 60.40 (Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971), with calendar dates and beginning and ending times of any CEMS downtime.
- (2) All flue gas desulfurization (FGD) system parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition **D.5.12** ~~D.5.15~~ - SO₂ Monitor Downtime.
- (3) **To document the compliance status with Condition D.5.2, The Permittee shall keep records of the daily average coal sulfur content, coal heat content, weighting factor, and daily average sulfur dioxide emission rate in pounds per MMBtu.**
- (4) **To document the compliance status with Condition D.5.2, the Permittee shall keep records of the pounds per million Btu (lbs/MMBtu) based on a thirty (30) day rolling weighted average.**

...

D.5.14 ~~D.5.16~~ Reporting Requirement

- (a) A quarterly report of ~~opacity exceedances~~ and a quarterly summary of the information to document the compliance status with Condition **D.5.2** ~~D.5.3~~ - Sulfur Dioxide (SO₂), shall be submitted not later than thirty (30) days following the end of each calendar quarter ~~until April 16, 2016 or~~ when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
...
- (c) ~~After January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later),~~ Permittee shall report any PM exceedances as part of its regular deviation reports.
- (d) **To document compliance with Condition D.5.2, the Permittee shall submit quarterly reports of daily average sulfur content, coal heat content, daily average sulfur dioxide emission rate in lbs per MMBtu, and the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per MMBtu shall be submitted to the department in the quarterly report and maintained by the source owner or operator for a period of at least two (2) years.**

D.5.15 ORDER of the Commissioner of the Indiana Department of Environmental Management

Pursuant to Indiana Code § 13-14-2-6 and in order to secure compliance with 40 CFR Part 63, Subpart UUUUU, Duke Energy, Inc. - Gibson Generating Station is subject to following ORDER:

1. Duke Energy, Inc. - Gibson Generating Station shall submit a status report within fifteen (15) days of completion of the following milestones indicating the actual dates of completion:
 - a. The date on-site construction for the installation of the emission control equipment identified in Attachment F for Gibson Unit 5 is initiated, and

- b. The date on-site construction for the installation of the emission control equipment identified in Attachment F for Gibson Unit 5 is completed.
 - c. The date by which final compliance with 40 CFR 63, Subpart UUUUU for Petersburg Unit 2 is achieved.
2. Duke Energy, Inc. - Gibson Generating Station Unit 5 shall comply with the HCL and PM compliance demonstration standards set forth in 40 CFR Part 63, Subpart UUUUU no later than April 16, 2016.
3. Duke Energy Indiana shall request a significant permit modification of its Part 70 permit pursuant to 326 IAC 2-7-12 within twelve (12) months of the date of this order to add the compliance schedule requirements contained in Order Paragraphs 1 and 2

Upon the effective date of this Order, all terms of the October 11, 2012 Order referenced above are no longer in effect.

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

D.7.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

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

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS

D.10.7 Reserved

~~D.10.7 Scrubber Parametric Monitoring [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]~~

- ~~(a) The Permittee shall monitor the flow rate of the scrubbing liquid daily. When for any one reading, the flow rate is below the normal minimum value established during the latest stack test, the Permittee shall take reasonable response steps. Failure to take response steps shall be considered a deviation from this permit. Section C - Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.~~
- ~~(b) The instruments used for determining the pressure, flow rate, and pH level 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 every six (6) months.~~

~~D.10.8 Record Keeping Requirements [40 CFR 64]~~

~~***~~

- ~~(d) To document compliance with Condition D.10.7(a), the Permittee shall maintain records of the flow rate of the scrubber. The Permittee shall include in its daily record when a reading is not taken and the reason for the lack of reading (e.g. the process did not operate that day).~~

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS

D.11.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the Preventive Maintenance Plan required by this condition.

SECTION E.1 ACID RAIN PROGRAM CONDITIONS
ORIS Code: 6113

Emissions Unit Description:

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with a flue gas conditioning system and an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack ~~D4~~.

Boiler No. 4 Stack D has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that~~

~~will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

(e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NOx during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack ~~5C~~.

Boiler No. 5 ~~Stack C~~ has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and Boiler 5 has a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NOx during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack ~~5C~~.

Boiler No. 5 ~~Stack C~~ has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and Boiler 5 has a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~
[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

...

E.2.2 New Source Performance Standards of Performance for Fossil-Fuel-Fired Steam Generators [40 CFR Part 60, Subpart D] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart D, the Permittee shall comply with the provisions of New Source Performance Standards of Performance for Fossil-Fuel-Fired Steam Generators, which are incorporated by reference as 326 IAC 12, (included as Attachment A of this permit), for the above emission unit as specified as follows:

- (1) 40 CFR 60.40 **(a)(1), (c)**
- (2) 40 CFR 60.41 **(a)**
- (3) 40 CFR 60.42 **(a)(1), (a)(2)**
- (4) 40 CFR 60.43 **(a)(2)**
- (5) 40 CFR 60.44 **(a)(3)**
- (6) 40 CFR 60.45 **(a), (c), (e), (g)**
- (7) 40 CFR 60.46

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

...

E.3.2 New Source Performance Standards for Standard of Performance for Non-metallic Mineral Processing Plants [40 CFR Part 60, Subpart OOO] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart OOO, the Permittee shall comply with the provisions of New Source Performance Standards for Standard of Performance for Non-metallic Mineral Processing Plants, which are incorporated by reference as 326 IAC 12, (included as Attachment B of this permit), for the above emission units as specified as follows:

- (1) 40 CFR 60.670(a)(1), (d)(1-3), (e-f)
- (2) 40 CFR 60.671
- (3) 40 CFR 60.672(a-b), (d-f), (e)(1-2), (f)
- (4) 40 CFR 60.673
- (5) 40 CFR 60.674(a)(1), (a)(2)
- (6) 40 CFR 60.675(b)(1), (b)(2), (c)(1)(i-ii); (c)(2)(i-ii); (c)(3), (d)(2)
- (7) 40 CFR 60.675(e)(1)(i-ii); (e)(2)(i-iii); (e)(3), (e)(4), (g)**
- ~~(8)~~ 40 CFR 60.676(a)(1), (a)(3), (a)(4), (f), (j), (k)
- (9) 40 CFR 60, Subpart OOO, Table 1**
- (10) 40 CFR 60, Subpart OOO, Table 2**
- (11) 40 CFR 60, Subpart OOO, Table 3**

E.5.2 National Emissions Standard for Hazardous Air Pollutants for stationary Reciprocating Internal Combustion Engines [40 CFR Part 63, Subpart ZZZZ][326 IAC 20-82-1]

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

- (1) 40 CFR 63.6585(a), (b)**
- (2) 40 CFR 63.6590(a)(2)(i)**
- (3) 40 CFR 63.6595(a)(1), (c)**
- ~~(4)~~ **(4)** 40 CFR 63.6600(d)
- ~~(5)~~ **(5)** 40 CFR 63.6605
- ~~(6)~~ **(6)** 40 CFR 63.6610
- ~~(7)~~ **(7)** 40 CFR 63.6625(h),(i)
- ~~(8)~~ **(8)** 40 CFR 63.6630
- ~~(9)~~ **(9)** 40 CFR 63.6635
- ~~(10)~~ **(10)** 40 CFR 63.6640
- ~~(11)~~ **(11)** 40 CFR 63.6645(a)(3)
- ~~(12)~~ **(12)** 40 CFR 63.6645(g)
- ~~(13)~~ **(13)** 40 CFR 63.6650
- ~~(14)~~ **(14)** 40 CFR 63.6655
- ~~(15)~~ **(15)** 40 CFR 63.6660
- ~~(16)~~ **(16)** 40 CFR 63.6665
- ~~(17)~~ **(17)** 40 CFR 63, Table 1a, 1b
- ~~(18)~~ **(18)** 40 CFR 63, Table 2a, 2b, 2c, 2d
- ~~(19)~~ **(19)** 40 CFR 63, Table 6
- ~~(20)~~ **(20)** 40 CFR 63, Table 7

SECTION E.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic**

precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), and with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 4.

Boiler No. 4 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x) sulfur dioxide (SO₂) and particulate matter (PM)

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 5.

Boiler No. 5 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM).

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

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

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

E.6.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.9065, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated by reference as 326 IAC 20-1-1, for the above listed emission unit, except as otherwise specified in 40 CFR Part 63, Subpart UUUUU, in accordance with the schedule in 40 CFR Part 63, Subpart UUUUU.

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

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, IN 46204-22551

E.6.2 Coal- And Oil-Fired Electric Utility Steam Generating Units NESHAP [40 CFR Part 63, Subpart UUUUU][326 IAC 20-89]

Pursuant to 40 CFR 63, Subpart UUUUU the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart UUUUU as applicable, which are incorporated by reference as 326 IAC 20-89 (included as Attachment F to this permit), for the above emission unit as specified as follows:

- (1) 40 CFR 63.9981
- (2) 40 CFR 63.9982(a)(1), (d)
- (3) 40 CFR 63.9984(b), (c), (f)
- (4) 40 CFR 63.9990(a)(1), (a)(2)
- (5) 40 CFR 63.9991(a)(1), (a)(2), (b), (c)(1), (c)(2)
- (6) 40 CFR 63.10000(a), (b), (c)(1)(iv); (v), (vi)(B), (d)(1), (d)(2)(i), (d)(2)(ii), (d)(3), (d)(4), (d)(5)(i-vii); (e), (l)
- (7) 40 CFR 63.10005(a), (a)(1), (a)(2)(i-iii); (b)(1-5); (d)(1), (d)(2)(i-iii); (d)(3), (e), (h)(1)(i)-(ii)(A-B); (h)(2)(i-ii); (h)(3)(i)(A-D); (h)(3)(ii); (h)(3)(iii)(A-B); (h)(3)(iii)(C)(1-5); (j), (k)
- (8) 40 CFR 63.10006(b)(1-2); (c), (d), (f), (i), (j)
- (9) 40 CFR 63.10007(a)(1), (a)(2), (b), (d), (e)(1), (e)(2), (f)(1)(ii) and (2); (g)
- (10) 40 CFR 63.10009(a), (b)(1), (b)(2), (d), (e), (f)(1), (g)(1), (h-k), (n)
- (11) 40 CFR 63.10010(a)(2)(ii); (b-e), (a)(4), (c-e), (f)(1-4); (g), (h)(1-7); (i)(1-5); (j)(1-4); (l)(1-5)
- (12) 40 CFR 63.10011(a-g)
- (13) 40 CFR 63.10020(a-d), (e)(1) - (3)(i)(A-D)
- (14) 40 CFR 63.10021(a-c); (d)(1-2); (e-i)
- (15) 40 CFR 63.10022
- (16) 40 CFR 63.10030(a), (b), (d), (e)
- (17) 40 CFR 63.10031(a-g)
- (18) 40 CFR 63.10032(a), (b), (d)(1)
- (1944) 40 CFR 63.10033(a-c)
- (2045) 40 CFR 63.10040

- (2146) 40 CFR 63.10041(a-b)
- (2247) 40 CFR 63.10042
- (2348) 40 CFR 63 Appendix A to Subpart UUUUU
- (24) 40 CFR 63, Subpart UUUUU, Table 2, Subcategory 1
- (25) 40 CFR 63, Subpart UUUUU, Table 3, Subcategory 1
- (26) 40 CFR 63, Subpart UUUUU, Table 5, Subcategories 1-5
- (27) 40 CFR 63, Subpart UUUUU, Table 7, Subcategory 1
- (28) 40 CFR 63, Subpart UUUUU, Table 8, Subcategory 1
- (29) 40 CFR 63, Subpart UUUUU, Table 9

SECTION F.1 SO₃ MITIGATION PLAN

Emissions Unit Description:

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with ~~a flue gas conditioning system~~ and an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack ~~4D~~.

Boiler No. 4 Stack-D has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack ~~5C~~.

Boiler No. 5 Stack-C has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and Boiler 5 has a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

SECTION G TR NO_x Annual Trading Program, TR NO_x Ozone Season Trading Program, and TR SO₂ Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.506), (40 CFR 97.606)

ORIS Code: 6137

Transport Rule (TR):

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

**Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)
[This facility is an affected source under 40 CFR 63, Subpart UUUUU]**

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) [This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 4.

**Boiler No. 4 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)
[This facility is an affected source under 40 CFR 63, Subpart UUUUU]**

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack 4.

**Boiler No. 5 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM)
[This facility is an affected source under 40 CFR 63, Subpart UUUUU]**

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

G.1 Designated representative requirements

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

- (1) 40 CFR 97.413 through 97.418;
- (2) 40 CFR 97.513 through 97.518; and
- (3) 40 CFR 97.613 through 97.618.

G.2 Emissions monitoring, reporting, and recordkeeping requirements

- (1) The owners and operators, and the designated representative, of each TR NO_x Annual source, TR NO_x Ozone Season source, and TR SO₂ Group 1 source, and each TR NO_x Annual unit at the source, TR NO_x 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).

- (2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of TR NO_x Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the TR NO_x Annual emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 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.**
- (3) The emissions data determined in accordance with 40 CFR 97.530 through 97.535 shall be used to calculate allocations of TR NO_x Ozone Season allowances under 40 CFR 97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NO_x Ozone Season emissions limitation and assurance provisions under paragraph (d) 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.**
- (4) 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 paragraph (e) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.**

G.3 NOX annual emissions requirements

- (1) TR NO_x Annual emissions limitation.**
 - (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_x Annual source and each TR NO_x Annual unit at the source shall hold, in the source's compliance account, TR NO_x 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 NO_x emissions for such control period from all TR NO_x Annual units at the source.**

- (ii). **If total NO_x emissions during a control period in a given year from the TR NO_x Annual units at a TR NO_x Annual source are in excess of the TR NO_x Annual emissions limitation set forth in paragraph (c)(1)(i) above, then:**

 - (A). **The owners and operators of the source and each TR NO_x Annual unit at the source shall hold the TR NO_x Annual allowances required for deduction under 40 CFR 97.424(d); and**
 - (B). **The owners and operators of the source and each TR NO_x Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.**
- (2) **TR NO_x Annual assurance provisions.**

 - (i). **If total NO_x emissions during a control period in a given year from all TR NO_x Annual units at TR NO_x 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 NO_x emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_x 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 NO_x emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_x emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_x emissions from all TR NO_x Annual units at TR NO_x Annual sources in the state for such control period exceed the state assurance level.**
 - (ii). **The owners and operators shall hold the TR NO_x Annual allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.**
 - (iii). **Total NO_x emissions from all TR NO_x Annual units at TR NO_x Annual sources in the State during a control period in a given year exceed the state assurance level if such total NO_x emissions exceed the sum, for such control period, of the state NO_x Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).**
 - (iv). **It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NO_x emissions from all TR NO_x Annual units at TR NO_x Annual sources in the State during a control period exceed the state assurance level or if a common designated representative's share of total**

NO_x emissions from the TR NO_x Annual units at TR NO_x Annual sources in the state during a control period exceeds the common designated representative's assurance level.

- (v). **To the extent the owners and operators fail to hold TR NO_x Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,**
 - (A). **The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and**
 - (B). **Each TR NO_x Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.**
- (3) **Compliance periods.**
 - (i). **A TR NO_x Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.**
 - (ii). **A TR NO_x Annual unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.**
- (4) **Vintage of allowances held for compliance.**
 - (i). **A TR NO_x Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a TR NO_x Annual allowance that was allocated for such control period or a control period in a prior year.**
 - (ii). **A TR NO_x Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NO_x Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.**
- (5) **Allowance Management System requirements. Each TR NO_x Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA.**
- (6) **Limited authorization. A TR NO_x Annual allowance is a limited authorization to emit one ton of NO_x during the control period in one year. Such authorization is limited in its use and duration as follows:**
 - (i). **Such authorization shall only be used in accordance with the TR NO_x Annual Trading Program; and**

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

(7) **Property right. A TR NO_x Annual allowance does not constitute a property right.**

G.4 NO_x ozone season requirements

(1) **TR NO_x Ozone Season emissions limitation.**

- (i). **As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_x Ozone Season source and each TR NO_x Ozone Season unit at the source shall hold, in the source's compliance account, TR NO_x Ozone Season allowances available for deduction for such control period under 40 CFR 97.524(a) in an amount not less than the tons of total NO_x emissions for such control period from all TR NO_x Ozone Season units at the source.**
- (ii). **If total NO_x emissions during a control period in a given year from the TR NO_x Ozone Season units at a TR NO_x Ozone Season source are in excess of the TR NO_x Ozone Season emissions limitation set forth in paragraph (d)(1)(i) above, then:**
 - (A). **The owners and operators of the source and each TR NO_x Ozone Season unit at the source shall hold the TR NO_x Ozone Season allowances required for deduction under 40 CFR 97.524(d); and**
 - (B). **The owners and operators of the source and each TR NO_x Ozone Season unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBB and the Clean Air Act.**

(2) **TR NO_x Ozone Season assurance provisions.**

- (i). **If total NO_x emissions during a control period in a given year from all TR NO_x Ozone Season units at TR NO_x Ozone Season sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_x emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_x Ozone Season allowances available for deduction for such control period under 40 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 NO_x emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such**

control period, by which each common designated representative's share of such NO_x emissions exceeds the respective common designated representative's assurance level; and

- (B). The amount by which total NO_x emissions from all TR NO_x Ozone Season units at TR NO_x Ozone Season sources in the state for such control period exceed the state assurance level.
 - (ii). The owners and operators shall hold the TR NO_x Ozone Season allowances required under paragraph (d)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.
 - (iii). Total NO_x emissions from all TR NO_x Ozone Season units at TR NO_x Ozone Season sources in the state during a control period in a given year exceed the state assurance level if such total NO_x emissions exceed the sum, for such control period, of the State NO_x Ozone Season trading budget under 40 CFR 97.510(a) and the state's variability limit under 40 CFR 97.510(b).
 - (iv). It shall not be a violation of 40 CFR part 97, subpart BBBBBB or of the Clean Air Act if total NO_x emissions from all TR NO_x Ozone Season units at TR NO_x Ozone Season sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total NO_x emissions from the TR NO_x Ozone Season units at TR NO_x Ozone Season sources in the state during a control period exceeds the common designated representative's assurance level.
 - (v). To the extent the owners and operators fail to hold TR NO_x Ozone Season allowances for a control period in a given year in accordance with paragraphs (d)(2)(i) through (iii) above,
 - (A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
 - (B). Each TR NO_x Ozone Season allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (d)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBBB and the Clean Air Act.
- (3) Compliance Periods.
- (i). A TR NO_x Ozone Season unit shall be subject to the requirements under paragraph (d)(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certificate requirements under 40 CFR 97.530(b) and for each control period thereafter.
 - (ii). A TR NO_x Ozone Season unit shall be subject to the requirements under paragraph (d)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.530(b) and for each control period thereafter.
- (4) Vintage of allowances held for compliance.

- (i). A TR NOx Ozone Season allowance held for compliance with the requirements under paragraph (d)(1)(i) above for a control period in a given year must be a TR NOx Ozone Season Allowance that was allocated for such control period or a control period in a prior year.
 - (ii). A TR NOx Ozone Season allowance held for compliance with the requirements under paragraphs (d)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NOx Ozone Season allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.
- (5) Allowances Management System Requirements.
- (i). Each TR NOx Ozone Season allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart BBBB.
- (6) Limited Authorization.
- (i). A TR NOx Ozone Season allowance is a limited authorization to emit one ton of NOx during the control period in one year. Such authorization is limited in its use and duration as follows:
 - (A). Such authorization shall only be used in accordance with the TR NOx Ozone Season Trading Program; and
 - (B). Notwithstanding any other provision of 40 CFR Part 97, Subpart BBBB, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
- (7) Property Right.
- (i). A TR NOx Ozone Season allowance does not constitute a property right.

G.5 SO₂ emissions requirements

- (1) TR SO₂ Group 1 emissions limitation.
- (i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO₂ Group 1 source and each TR SO₂ Group 1 unit at the source shall hold, in the source's compliance account, TR SO₂ Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO₂ emissions for such control period from all TR SO₂ Group 1 units at the source.
 - (ii). If total SO₂ emissions during a control period in a given year from the TR SO₂ Group 1 units at a TR SO₂ Group 1 source are in excess of the TR SO₂ Group 1 emissions limitation set forth in paragraph (e)(1)(i) above, then:
 - (A). The owners and operators of the source and each TR SO₂ Group 1 unit at the source shall hold the TR SO₂ Group 1 allowances required for deduction under 40 CFR 97.624(d); and

- (B).** The owners and operators of the source and each TR SO₂ Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(2) TR SO₂ Group 1 assurance provisions

- (i).** If total SO₂ emissions during a control period in a given year from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO₂ emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO₂ Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—
- (A).** The quotient of the amount by which the common designated representative's share of such SO₂ emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such SO₂ emissions exceeds the respective common designated representative's assurance level; and
- (B).** The amount by which total SO₂ emissions from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state for such control period exceed the state assurance level.
- (ii).** The owners and operators shall hold the TR SO₂ Group 1 allowances required under paragraph (e)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.
- (iii).** Total SO₂ emissions from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO₂ emissions exceed the sum, for such control period, of the state SO₂ Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).
- (iv).** It shall not be a violation of 40 CFR part 97, subpart CCCCC or of the Clean Air Act if total SO₂ emissions from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total SO₂ emissions from the TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.

- (v). **To the extent the owners and operators fail to hold TR SO₂ Group 1 allowances for a control period in a given year in accordance with paragraphs (e)(2)(i) through (iii) above,**
 - (A). **The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and**
 - (B). **Each TR SO₂ Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (e)(2)(i) through (iii) 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.**
- (3) **Compliance periods.**
 - (i). **A TR SO₂ Group 1 unit shall be subject to the requirements under paragraph (e)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.**
 - (ii). **A TR SO₂ Group 1 unit shall be subject to the requirements under paragraph (e)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.**
- (4) **Vintage of allowances held for compliance.**
 - (i). **A TR SO₂ Group 1 allowance held for compliance with the requirements under paragraph (e)(1)(i) 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.**
 - (ii). **A TR SO₂ Group 1 allowance held for compliance with the requirements under paragraphs (e)(1)(ii)(A) and (2)(i) through (iii) 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.**
- (5) **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.**
- (6) **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:**
 - (i). **Such authorization shall only be used in accordance with the TR SO₂ Group 1 Trading Program; and**
 - (ii). **Notwithstanding any other provision of 40 CFR part 97, subpart CCCCC, the Administrator has the authority to terminate or limit the use and**

duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

- (7) Property right. A TR SO₂ Group 1 allowance does not constitute a property right.**

G.6 Title V Permit Revision Requirements

- (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_x Annual allowances in accordance with 40 CFR part 97, subpart AAAAA, TR NO_x Ozone Season allowances in accordance with 40 CFR part 97, subpart BBBBB, and TR SO₂ Group 1 allowances in accordance with 40 CFR part 97, subpart CCCCC.**
- (2) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, 40 CFR 97.530 through 97.535, and 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2), 40 CFR 97.506(d)(2), and 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).**

G.7 Additional recordkeeping and reporting requirements

- (1) Unless otherwise provided, the owners and operators of each TR NO_x Annual source and each TR NO_x Annual unit, TR NO_x Ozone Season source and each TR NO_x Ozone Season unit, and TR SO₂ Group 1 source and each TR SO₂ Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.**
- (i). The certificate of representation under 40 CFR 97.416, 40 CFR 97.516, and 40 CFR 97.616 for the designated representative for the source and each TR NO_x Annual unit, TR NO_x Ozone Season unit, and TR SO₂ Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416, 40 CFR 97.516, and 40 CFR 97.616 changing the designated representative.**
- (ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA, 40 CFR part 97, subpart BBBBB, and 40 CFR part 97, subpart CCCCC.**
- (iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_x Annual Trading Program, TR NO_x Ozone Season Trading Program, and TR SO₂ Group 1 Trading Program.**
- (2) The designated representative of a TR NO_x Annual source and each TR NO_x Annual unit, a TR NO_x Ozone Season source and each TR NO_x 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 NO_x Annual Trading Program, TR NO_x Ozone Season Trading Program, and TR SO₂ Group 1 Trading Program, except as provided in 40 CFR 97.418, 40 CFR 97.518, and 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

G.8 Liability

- (1) Any provision of the TR NO_x Annual Trading Program that applies to a TR NO_x Annual source or the designated representative of a TR NO_x Annual source shall also apply to the owners and operators of such source and of the TR NO_x Annual units at the source.
- (2) Any provision of the TR NO_x Annual Trading Program that applies to a TR NO_x Annual unit or the designated representative of a TR NO_x Annual unit shall also apply to the owners and operators of such unit.
- (3) Any provision of the TR NO_x Ozone Season Trading Program that applies to a TR NO_x Ozone Season source or the designated representative of a TR NO_x Ozone Season source shall also apply to the owners and operators of such source and of the TR NO_x Ozone Season units at the source.
- (4) Any provision of the TR NO_x Ozone Season Trading Program that applies to a TR NO_x Ozone Season unit or the designated representative of a TR NO_x Ozone Season unit shall also apply to the owners and operators of such unit.
- (5) Any provision of the TR SO₂ Group 1 Trading Program that applies to a TR SO₂ Group 1 source or the designated representative of a TR SO₂ Group 1 source shall also apply to the owners and operators of such source and of the TR SO₂ Group 1 units at the source.
- (6) Any provision of the TR SO₂ Group 1 Trading Program that applies to a TR SO₂ Group 1 unit or the designated representative of a TR SO₂ Group 1 unit shall also apply to the owners and operators of such unit.

G.9 Effect on other authorities

No provision of the TR NO_x Annual Trading Program or exemption under 40 CFR 97.405, TR NO_x Ozone Season Trading Program or exemption under 40 CFR 97.505, and TR SO₂ 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_x Annual source or TR NO_x Annual unit, TR NO_x Ozone Season source or TR NO_x Ozone Season unit, and TR SO₂ Group 1 source or TR SO₂ 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.

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

ORIS Code: 6113

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

- (a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu

per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 1 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5875 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 1-2.

Boiler No. 2 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 3, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with ~~a flue gas conditioning system and~~ an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system to control sulfur dioxide (SO₂) emissions, and exhausting to a new stack, identified as Stack 3.

Boiler No. 3 has its own continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 4, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 5897 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack ~~D4~~.

Boiler No. 4 ~~Stack D~~ has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) ~~and a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of January 1, 2015 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

- (e) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 5, installed in 1982, with a nominal heat input capacity of 5900 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, equipped with Selective Catalytic Reduction (SCR) for control of NO_x during the ozone season, with a flue gas desulfurization (FGD) system for control of sulfur dioxide, and exhausting to stack ~~D~~5.

Boiler No. 5 Stack C has continuous emissions monitors (CEMs) for nitrogen oxides (NO_x), sulfur dioxide (SO₂) and particulate matter (PM) and ~~Boiler 5 has a continuous opacity monitor (COM) that will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit (whichever is later).~~

[This facility is an affected source under 40 CFR 63, Subpart UUUUU]

Conclusion and Recommendation

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant. An application for the purposes of this review was received on March 23, 2016.

IDEM Contact

- (a) Questions regarding this proposed permit can be directed to Vasantha Palakurti at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 234-9694 or toll free at 1-800-451-6027 extension 4-9694.
- (b) A copy of the findings is available on the Internet at: <http://www.in.gov/ai/appfiles/idem-caats/>
- (c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Permit Guide on the Internet at: <http://www.in.gov/idem/5881.htm>; and the Citizens' Guide to IDEM on the Internet at: <http://www.in.gov/idem/6900.htm>.



Indiana Department of Environmental Management

We Protect Hoosiers and Our Environment.

100 N. Senate Avenue • Indianapolis, IN 46204

(800) 451-6027 • (317) 232-8603 • www.idem.IN.gov

Michael R. Pence
Governor

Carol S. Comer
Commissioner

October 6, 2016

Sheryl Fisher
Duke Energy Indiana, LLC - Gibson Generating Station
1000 E Main St
Plainfield, IN 46168

Re: Public Notice
Duke Energy Indiana, LLC - Gibson Generating Station
Permit Level: Title V - Significant Permit Modification
Permit Number: 051 - 36994 - 00013

Dear Sheryl Fisher:

Enclosed is a copy of your draft Title V - Significant Permit Modification, Technical Support Document, emission calculations, and the Public Notice which will be printed in your local newspaper.

The Office of Air Quality (OAQ) has prepared two versions of the Public Notice Document. The abbreviated version will be published in the newspaper, and the more detailed version will be made available on the IDEM's website and provided to interested parties. Both versions are included for your reference. The OAQ has requested that the Princeton Daily Clarion in Princeton, Indiana publish the abbreviated version of the public notice no later than October 10, 2016. You will not be responsible for collecting any comments, nor are you responsible for having the notice published in the newspaper.

OAQ has submitted the draft permit package to the Owensville Carnegie Public library, 110 S Main St in Owensville IN. As a reminder, you are obligated by 326 IAC 2-1.1-6(c) to place a copy of the complete permit application at this library no later than ten (10) days after submittal of the application or additional information to our department. We highly recommend that even if you have already placed these materials at the library, that you confirm with the library that these materials are available for review and request that the library keep the materials available for review during the entire permitting process.

Please review the enclosed documents carefully. This is your opportunity to comment on the draft permit and notify the OAQ of any corrections that are needed before the final decision. Questions or comments about the enclosed documents should be directed to Vasantha Palakurti, Indiana Department of Environmental Management, Office of Air Quality, 100 N. Senate Avenue, Indianapolis, Indiana, 46204 or call (800) 451-6027, and ask for extension 4-9694 or dial (317) 234-9694.

Sincerely,

Len Pogost

Len Pogost
Permits Branch
Office of Air Quality

Enclosures
PN Applicant Cover letter 2/17/2016



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Commissioner

ATTENTION: PUBLIC NOTICES, LEGAL ADVERTISING

October 5, 2016

Princeton Daily Clarion
Attn: Classifieds
P.O. Box 30
Princeton, Indiana 47670-0321

Enclosed, please find one Indiana Department of Environmental Management Notice of Public Comment for Duke Energy Indiana, LLC - Gibson Generating Station, Gibson County, Indiana.

Since our agency must comply with requirements which call for a Notice of Public Comment, we request that you print this notice one time, no later than October 12, 2016.

Please send a notarized form, clippings showing the date of publication, and the billing to the Indiana Department of Environmental Management, Accounting, Room N1345, 100 North Senate Avenue, Indianapolis, Indiana, 46204.

To ensure proper payment, please reference account # 100174737.

We are required by the Auditor's Office to request that you place the Federal ID Number on all claims. If you have any conflicts, questions, or problems with the publishing of this notice or if you do not receive complete public notice information for this notice, please call Len Pogost at 800-451-6027 and ask for extension 3-2803 or dial 317-233-2803.

Sincerely,

Len Pogost

Len Pogost
Permit Branch
Office of Air Quality

Permit Level: Title V - Significant Permit Modification
Permit Number: 051 - 36994 - 00013

Enclosure
PN Newspaper.dot 6/13/2013



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Michael R. Pence
Governor

Carol S. Comer
Commissioner

October 6, 2016

To: Owensville Carnegie Public 110 S Main St Owensville IN

From: Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Subject: **Important Information to Display Regarding a Public Notice for an Air Permit**

Applicant Name: Duke Energy Indiana, LLC - Gibson Generating Station
Permit Number: 051 - 36994 - 00013

Enclosed is a copy of important information to make available to the public. This proposed project is regarding a source that may have the potential to significantly impact air quality. Librarians are encouraged to educate the public to make them aware of the availability of this information. The following information is enclosed for public reference at your library:

- Notice of a 30-day Period for Public Comment
- Request to publish the Notice of 30-day Period for Public Comment
- Draft Permit and Technical Support Document

You will not be responsible for collecting any comments from the citizens. Please refer all questions and request for the copies of any pertinent information to the person named below.

Members of your community could be very concerned in how these projects might affect them and their families. **Please make this information readily available until you receive a copy of the final package.**

If you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185. Questions pertaining to the permit itself should be directed to the contact listed on the notice.

Enclosures
PN Library.dot 2/16/2016



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Michael R. Pence
Governor

Carol S. Comer
Commissioner

Notice of Public Comment

October 6, 2016

Duke Energy Indiana, LLC - Gibson Generating Station

051 - 36994 - 00013

Dear Concerned Citizen(s):

You have been identified as someone who could potentially be affected by this proposed air permit. The Indiana Department of Environmental Management, in our ongoing efforts to better communicate with concerned citizens, invites your comment on the draft permit.

Enclosed is a Notice of Public Comment, which has been placed in the Legal Advertising section of your local newspaper. The application and supporting documentation for this proposed permit have been placed at the library indicated in the Notice. These documents more fully describe the project, the applicable air pollution control requirements and how the applicant will comply with these requirements.

If you would like to comment on this draft permit, please contact the person named in the enclosed Public Notice. Thank you for your interest in the Indiana's Air Permitting Program.

Please Note: *If you feel you have received this Notice in error, or would like to be removed from the Air Permits mailing list, please contact Patricia Pear with the Air Permits Administration Section at 1-800-451-6027, ext. 3-6875 or via e-mail at PPEAR@IDEM.IN.GOV. If you have recently moved and this Notice has been forwarded to you, please notify us of your new address and if you wish to remain on the mailing list. Mail that is returned to IDEM by the Post Office with a forwarding address in a different county will be removed from our list unless otherwise requested.*

Enclosure
PN AAA Cover.dot 2/17/2016



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Michael R. Pence
Governor

Carol S. Comer
Commissioner

AFFECTED STATE NOTIFICATION OF PUBLIC COMMENT PERIOD DRAFT INDIANA AIR PERMIT

October 6, 2016

A 30-day public comment period has been initiated for:

Permit Number: 051 - 36994 - 00013
Applicant Name: Duke Energy Indiana, LLC - Gibson Generating Station
Location: Owensville, Gibson County, Indiana

The public notice, draft permit and technical support documents can be accessed via the **IDEM Air Permits Online** site at:

<http://www.in.gov/ai/appfiles/idem-caats/>

Questions or comments on this draft permit should be directed to the person identified in the public notice by telephone or in writing to:

Indiana Department of Environmental Management
Office of Air Quality, Permits Branch
100 North Senate Avenue
Indianapolis, IN 46204

Questions or comments regarding this email notification or access to this information from the EPA Internet site can be directed to Chris Hammack at chammack@idem.IN.gov or (317) 233-2414.

Affected States Notification.dot 2/17/2016

Mail Code 61-53

IDEM Staff	LPOGOST 10/6/2016 Duke Energy Indiana LLC - Gibson Generating Station 051 - 36994 - 00013 draft		AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	 Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: CERTIFICATE OF MAILING ONLY	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee	Remarks
1		Sheryl Fisher Duke Energy Indiana LLC - Gibson Generating Station 1000 E Main St Plainfield IN 46168 (Source CAATS)										
2		Michael Mosley Station Manager Duke Energy Indiana LLC - Gibson Generating Station 1000 E Main St Plainfield IN 46168 (RO CAATS)										
3		Owensville Carnegie Public 110 S Main St Owensville IN 47665-0218 (Library)										
4		Princeton City Council and Mayors Office 603 South Main Street Princeton IN 47670 (Local Official)										
5		Gibson County Health Department 203 S Prince Street, Suite A Princeton IN 47670 (Health Department)										
6		Eric Anderson 25 Atlantic Avenue Erlanger KY 41018 (Affected Party)										
7		Gibson County Commissioners 101 N. Main Street Princeton IN 47670 (Local Official)										
8		Oakland City Town Council and Mayors Office 301 S Franklin Street Oakland City IN 47660 (Local Official)										
9		Mr. Mark Wilson Evansville Courier & Press P.O. Box 268 Evansville IN 47702-0268 (Affected Party)										
10		Owensville Town Council PO Box 296 Owensville IN 47665 (Local Official)										
11		Mr. Bil Musgrove PO Box 520 Chandler IN 47610 (Affected Party)										
12		David Boggs 216 Western Hills Dr Mt Vernon IN 47620 (Affected Party)										
13		John Blair 800 Adams Ave Evansville IN 47713 (Affected Party)										
14												
15												

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