INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We make Indiana a cleaner, healthier place to live.

Mitchell E. Daniels, Jr.
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
(800) 451-6027
www.IN.gov/idem

TO: Interested Parties / Applicant

DATE: January 26, 2009

RE: SIGECO A.B. Brown Generating Station / 129-26415-00010

FROM: Matthew Stuckey, Deputy Branch Chief
Permits Branch
Office of Air Quality

Notice of Decision: Approval – Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the enclosed matter. Pursuant to IC 13-15-5-3, this permit is effective immediately, unless a petition for stay of effectiveness is filed and granted, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3-7 and IC 13-15-6-1(b) or IC 13-15-6-1(a) require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204.

For an **initial Title V Operating Permit**, a petition for administrative review must be submitted to the Office of Environmental Adjudication within **thirty (30)** days from the receipt of this notice provided under IC 13-15-5-3, pursuant to IC 13-15-6-1(b).

For a **Title V Operating Permit renewal**, a petition for administrative review must be submitted to the Office of Environmental Adjudication within **fifteen (15)** days from the receipt of this notice provided under IC 13-15-5-3, pursuant to IC 13-15-6-1(a).

The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:
(1) the date the document is delivered to the Office of Environmental Adjudication (OEA);
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OEA by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OEA by private carrier.

The petition must include facts demonstrating that you are either the applicant, a person aggrieved or adversely affected by the decision or otherwise entitled to review by law. Please identify the permit, decision, or other order for which you seek review by permit number, name of the applicant, location, date of this notice and all of the following:

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(1) the name and address of the person making the request;
(2) the interest of the person making the request;
(3) identification of any persons represented by the person making the request;
(4) the reasons, with particularity, for the request;
(5) the issues, with particularity, proposed for considerations at any hearing; and
(6) identification of the terms and conditions which, in the judgment of the person making the request, would be appropriate in the case in question to satisfy the requirements of the law governing documents of the type issued by the Commissioner.

Pursuant to 326 IAC 2-7-18(d), any person may petition the U.S. EPA to object to the issuance of an initial Title V operating permit, permit renewal, or modification within sixty (60) days of the end of the forty-five (45) day EPA review period. Such an objection must be based only on issues that were raised with reasonable specificity during the public comment period, unless the petitioner demonstrates that it was impractible to raise such issues, or if the grounds for such objection arose after the comment period.

To petition the U.S. EPA to object to the issuance of a Title V operating permit, contact:

U.S. Environmental Protection Agency
401 M Street
Washington, D.C. 20406

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178. Callers from within Indiana may call toll-free at 1-800-451-6027, ext. 3-0178.

Enclosures
FNTVOP.dot12/3/07

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.

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Governor

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Toll Free (800) 451-6027
www.idem.IN.gov

Part 70 Operating Permit Renewal
OFFICE OF AIR QUALITY

Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
8511 Welborn Road,
Mount Vernon47620, Indiana

(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.: T129-26415-00010	
Issued by: Tripurari Sinha Tripurari P. Sinha, Ph. D., Section Chief Permits Branch Office of Air Quality	Issuance Date: January 26, 2009 Expiration Date: January 26, 2013

TABLE OF CONTENTS

A. SOURCE SUMMARY 7
- A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(15)][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(15)]
- A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)][326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)]
- A.4 Part 70 Permit Applicability [326 IAC 2-7-2]

B. GENERAL CONDITIONS 11
- 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]
- 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(1),(3) and (13)][326 IAC 2-7-6(1) and (6)] [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 Deviations from Permit Requirements and Conditions [326 IAC 2-7-5(3)(C)(ii)]
- B.16 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.17 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]
- B.18 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12] [40 CFR 72]
- B.19 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)] [326 IAC 2-7-12(b)(2)]
- B.20 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]
- B.21 Source Modification Requirement [326 IAC 2-7-10.5]
- B.22 Inspection and Entry [326 IAC 2-7-6][IC 13-14-2-2][IC 13-30-3-1][IC 13-17-3-2]
- B.23 Transfer of Ownership or Operational Control [326 IAC 2-7-11]
- B.24 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)][326 IAC 2-1.1-7]
- B.25 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314] [326 IAC 1-1-6]

C. SOURCE OPERATION CONDITIONS 22

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]
- 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 Motor Vehicle Fugitive Dust Sources [326 IAC 6-4-4]
- C.7 Stack Height [326 IAC 1-7]
- C.8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

Testing Requirements [326 IAC 2-7-6(1)]
C.9 Performance Testing [326 IAC 3-6]

Compliance Requirements [326 IAC 2-1.1-11]
C.10 Compliance Requirements [326 IAC 2-1.1-11]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]
C.11 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)]
C.12 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]
C.13 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]
C.14 Monitoring Methods [326 IAC 3] [40 CFR 60] [40 CFR 63]
C.15 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]
C.16 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]
C.17 Risk Management Plan [326 IAC 2-7-5(12)] [40 CFR 68]
C.18 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]
C.19 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]
C.20 Emission Statement [326 IAC 2-7-5(3)(iii)] [326 IAC 2-7-5(7)] [326 IAC 2-7-19(c)] [326 IAC 2-6]
C.21 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]
C.22 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11]

Stratospheric Ozone Protection
C.23 Compliance with 40 CFR 82 and 326 IAC 22-1

Ambient Monitoring Requirement [326 IAC 7-3]
C.24 Ambient Monitoring [326 IAC 7-3]

D.1. EMISSIONS UNIT OPERATION CONDITIONS 31

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.1.1 Sulfur Dioxide (SO2) [326 IAC 7-1.1-2]
D.1.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]
D.1.3 Operation Standards [326 IAC 2-1.1-5(a)(4)] [40 CFR 261] [40 CFR 279] [326 IAC 13]
D.1.4 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

Compliance Determination Requirements
D.1.5 Testing Requirements [326 IAC 2-1.1-11] [40 CFR 60 Subpart D]
D.1.6 Operation of Fabric Filter
D.1.7 Scrubber Operation
D.1.8 Continuous Emissions Minotoring [326 IAC 3-5] [326 IAC 12] [40 CFR 60 Subpart D]
D.1.9 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 2-1.1-5(a)(4)]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]
D.1.10 Parametric Monitoring
D.1.11 Broken or Failed Bag Detection
D.1.12 SO2 Monitoring System Downtime [326 IAC 2-7-6] [326 2-7-5(3)]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.1.13 Record Keeping Requirements
D.1.14 Reporting Requirements

D.2. EMISSIONS UNIT OPERATION CONDITIONS 35

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.2.1 PSD Minor Limits [326 IAC 2-2]
D.2.2 SO2 PSD BACT Requirements [326 IAC 2-2-3]
D.2.3 Sulfur Dioxide (SO2) [326 IAC 7-1.1-2]
D.2.4 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]
D.2.5 Operation Standards [326 IAC 2-1.1-5(a)(4)] [40 CFR 261] [40 CFR 279] [326 IAC 13]
D.2.6 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

Compliance Determination Requirements
D.2.7 Testing Requirements [326 IAC 2-1.1-11] [40 CFR 60 Subpart Da]
D.2.8 Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]
D.2.9 Scrubber Operation
D.2.10 Continuous Emissions Minotoring [326 IAC 3-5] [326 IAC 12] [40 CFR 60 Subpart D]
D.2.11 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-7-4] [326 IAC 7-2]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]
D.2.12 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]
D.2.13 SO2 Monitoring System Downtime [326 IAC 2-7-6] [326 2-7-5(3)]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.2.14 Record Keeping Requirement
D.2.15 Reporting Requirements

D.3. EMISSIONS UNIT OPERATION CONDITIONS 39

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.3.1 PSD Minor Limits [326 IAC 2-2]
D.3.2 Sulfur Dioxide (SO2) [326 IAC 7-1.1-2]
D.3.3 Opacity [326 IAC 5-1]
D.3.4 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

Compliance Determination Requirements
D.3.5 Continuous Emissions Minotoring [326 IAC 3-5]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]
D.3.6 Visible Emission Notation

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

D.4. EMISSIONS UNIT OPERATION CONDITIONS 42

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.4.1 PM10 PSD BACT Requirements [326 IAC 2-2-3]
D.4.2 NOx PSD BACT Requirements [326 IAC 2-2-3]
D.4.3 CO PSD BACT Requirements [326 IAC 2-2-3]
D.4.4 Startup and Shutdown Limitations for Combustion Turbines
D.4.5 Hazardous Air Pollutants PSD BACT [326 IAC 2-2-3]
D.4.6 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

Compliance Determination Requirements
D.4.7 Continuous Emissions Minotoring [326 IAC 3-5]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.4.8 Record Keeping Requirement
D.4.9 Reporting Requirement

D.5. EMISSIONS UNIT OPERATION CONDITIONS 46

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.5.1 Particulate Emission Limitations for Manufacturing Process [326 IAC 6-3-2]
D.5.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

Compliance Determination Requirements
D.5.3 Particulate Matter (PM)

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

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

D.6. EMISSIONS UNIT OPERATION CONDITIONS 48

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.6.1 Particulate Emission Limitations for Manufacturing Process [326 IAC 6-3-2]
D.6.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

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

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

D.7. EMISSIONS UNIT OPERATION CONDITIONS 50

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.7.1 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]
D.7.2 Visible Emission Notations

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.7.3 Record Keeping Requirement

D.8. EMISSIONS UNIT OPERATION CONDITIONS 52

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.8.1 Organic Solvent Degreasing Operations: Cold Cleaner Operations [326 IAC 8-3-2]

D.8.2 Organic Solvent Degreasing Operations: Cold Cleaner Operations and Control [326 IAC 8-3-5]
D.8.3 Particulate Emission Limitations for Manufacturing Process [326 IAC 6-3-2]

E.1. EMISSIONS UNIT OPERATION CONDITIONS 54

Emission Limitations and Standards [326 IAC 2-7-5(1)]
E.1.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR 60, Subpart A]
E.1.2 Standard of Performace for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971 [326 IAC 12-1] [40 CFR 60, Subpart D]

E.2. EMISSIONS UNIT OPERATION CONDITIONS 55

Emission Limitations and Standards [326 IAC 2-7-5(1)]
E.2.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR 60, Subpart A]
E.2.2 Standard of Performace for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 [326 IAC 12-1] [40 CFR 60, Subpart Da]

E.3. EMISSIONS UNIT OPERATION CONDITIONS 56

Emission Limitations and Standards [326 IAC 2-7-5(1)]
E.3.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR 60, Subpart A]
E.3.2 Standard of Performace for Stationary Gas Turbines [326 IAC 12-1] [40 CFR 60, Subpart GG]

E.4. EMISSIONS UNIT OPERATION CONDITIONS 57

Acid Rain Program
E.4.1 Acid Raain Permit [2-7-5(1)(C)] [326 IAC 21] [40 CFR 72 through 40 CFR 78]
E.4.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)] [326 IAC 21]

F.1. EMISSIONS UNIT OPERATION CONDITIONS 59

F Nitrogen Oxides Budget Trading Program - NO_X Budget Permit for NO_X Budget Units Under 326 IAC 10-4-1(a)
F.1 Automatic Incorporation of Definitions [326 IAC 10-4-7(e)]
F.2 Standard Permit Requirements [326 IAC 10-4-4(a)]
F.3 Monitoring Requirements [326 IAC 10-4-4(b)]
F.4 Nitrogen Oxides Requirements [326 IAC 10-4-4(c)]
F.5 Excess Emissions Requirements [326 IAC 10-4-4(d)]
F.6 Record Keeping Requirements [326 IAC 10-4-4(e)] [326 IAC 2-7-5(3)]
F.7 Reporting Requirements [326 IAC 10-4-4(e)]
F.8 Liability [326 IAC 10-4-4(f)]
F.9 Effect on Other Authorities [326 IAC 10-4-4(g)]

Certification 64
Emergency Occurrence Report 65
Semi-Annual Natural Gas Fired Boiler Certification 67
Quarterly Report 68-71
Quarterly Deviation and Compliance Monitoring Report 72

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(15)][326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary electric uitility generating Station.

Source Address:	8511 Welborn Road,, Mount Vernon47620, Indiana
Mailing Address:	20 Northwest Fourth Street, Evansville, IN 47741
General Source Phone Number:	812-491-4562
SIC Code:	4911 and 3299
County Location:	Posey
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(15)]

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

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

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

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

(d) One (1) simple cycle natural gas-fired combustion turbine, designated as unit ABB No. 4, with constructed 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV) with inlet fogger for power augmentation during high ambient temperature operation, with dry low-NOx combustion, with continuous emissions monitoring (CEM) system for nitrogen oxides (NO_X) and carbon monoxide (CO), exhausting to stack No.4.

(e) A coal storage and handling system, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit 2 boiler, with a maximum throughput of 600 tons of coal per hour, consisting of the following equipment:

(1) One (1) railcar and truck unloading station with particulate emissions controlled by enclosure, with a drop point to the coal pile.
(2) One (1) storage pile, having a storage capacity of 700,000 tons, with fugitive emissions controlled by a watering system.

(3) An enclosed conveyor system, with a maximum feed rate of 600 tons per hour, with the transfer points underground or enclosed by buildings, and exhausting inside the transfer buildings or powerhouse.

(4) Twelve (12) enclosed coal pulverizers, each with a maximum capacity of twenty (20) tons of coal per hour, and exhausting to the boilers

(f) A lime storage and handling system, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit 2 boiler, consisting of the following equipment:

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

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

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

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

(g) A soda ash storage and handling system, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit 2 boiler, consisting of the following equipment:

(1) One (1) railcar and truck unloading station, with particulate matter emissions controlled by enclosure, with pneumatic conveyance to the storage silos, with a maximum flow rate of 1500 cfm.
(2) Two (2) storage silos, each with a maximum capacity of 200 tons, each with a fabric filter to recover the pneumatically conveyed material.

(h) The wet fly and bottom ash handling system was installed and expanded with start-up dates of 1979 (installed with Unit No. 1) and 1985 (installed with Unit No. 2). The dry fly ash (DFA) system was subsequently added to accommodate the option for product recovery of DFA material through a separate storage, handling, and barging operation to an off-site location. The DFA handling system interfaces with the existing wet ash system at the Hydroveyor. (Hydroveyor No. 1 for A. B. Brown No. 1 and Hydroveyor No. 2 for A. B. Brown No. 2). Each existing Hydroveyor is a water-exhauster powered-vacuum system that conveys ash in a dry state up to the exhauster where it then converts to

slurry form and then flows to an ash separator where the conveying air is vented off and the slurry flows by gravity to the existing ash pond. The existing handling system was modified to incorporate the all-dry filter/separator design (Filter/Separator No. 1 for A. B. Brown No. 1 and Filter/Separator No. 2 for A. B. Brown No. 2). Each Hydroveyor remains in-service and each filter/separator, with bypasses, intercept the fly ash for transport to the storage silo. Each existing Hydroveyor continues to discharge water to the existing ash pond and the existing fly ash system continues to route fly ash slurry flows to the ash pond for maintenance or product quality episodes. The filter/separators discharge to the Intermediate Silo (storage capacity of 2500 tons). The Intermediate Silo is equipped with a bin vent filter and truck unloading station. The truck unloading station receives ash from other Vectren operations for transfer to the Barge Loader. The truck unloading station is equipped with two truck bays to receive ash product. The transport and handling system that extends from the Intermediate Silo and through to the Barge Loader is a common (single) system with a design capacity of 700 tph. The Intermediate Silo discharge is fitted with a feeder to load the dry conveyor (belt) for transport to the Barge Loading Transfer Tower. The Barge Loading Transfer Tower conveys DFA, via air-slide, to the barge. The DFA product enters the barge through a telescopic loading nozzle fitted with a dust control ring to control fugitive dust. The Barge Loader conveyor is equipped with a fabric filter dust collector which vents to the atmosphere.

(i) Scrubber sludge handling, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit 2 boiler, with wet sludge conveyed to haul trucks.

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)][326 IAC 2-7-4(c)][326 IAC 2-7-5(15)]

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

(a) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6. [326 IAC 8-3-2] [326 IAC 8-3-5]

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

(c) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(1) Boiler Chemical Cleaning waste evaporation

(2) Ash pond and ash pond maintenance, with water cover or vegetation sufficient to prevent ash re-entrainment.

(3) Facility waste oil incineration.

(d) The following equipment related to manufacturing activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

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, T129-26415-00010, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

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

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

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

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

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

B.4 Enforceability [326 IAC 2-7-7]

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. The submittal by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34). 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) Where specifically designated by this permit or required by an applicable requirement, any application form, report, or compliance certification submitted shall contain certification by the "responsible official" of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) One (1) certification shall be included, using the attached Certification Form, 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(34).

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 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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)][326 IAC 2-7-6(1) and (6)][326 IAC 1-6-3]

(a) The Permittee shall maintain and implement Preventive Maintenance Plans (PMPs) within ninety (90) days after issuance of this permit, for the sources described in 326 IAC 1-6-3. At a minimum the PMPs shall contain 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.

(b) 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. If an exceedance of an emission limit has occurred and a deficient PMP(s) was the cause or the primary contributor of the exceedance, then IDEM, OAQ may require the Permittee to revise its PMPs as necessary to avoid a future exceedance. The PMPs do not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) 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, and 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 Section), or
Telephone Number: 317-233-0178 (ask for Compliance Section)

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 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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(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)(9) 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.

(h) The Permittee shall include all emergencies in the Quarterly Deviation and Compliance Monitoring Report.

B.12 Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]

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

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

(b) If, after issuance of this permit, it is determined that the permit is in nonconformance with an applicable requirement that applied to the source on the date of permit issuance, IDEM, OAQ, shall immediately take steps to reopen and revise this permit and issue a compliance order to the Permittee to ensure expeditious compliance with the applicable requirement until the permit is reissued. The permit shield shall continue in effect so long as the Permittee is in compliance with the compliance order.

(c) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the permit application. Erroneous information means information that the Permittee knew to be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.

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

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

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

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

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

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

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

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

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

(a) All terms and conditions of permits established prior to T129-26415-00010 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

(2) revised under 326 IAC 2-7-10.5, or

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

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

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

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

B.15 Deviations from Permit Requirements and Conditions [326 IAC 2-7-5(3)(C)(ii)]

(a) Deviations from any permit requirements (for emergencies see Section B - Emergency Provisions), the probable cause of such deviations, and any response steps or preventive measures taken shall be reported to:

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

using the attached Quarterly Deviation and Compliance Monitoring Report, or its equivalent. 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.

The Quarterly Deviation and Compliance Monitoring Report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

B.16 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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(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.17 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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, 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 in writing by IDEM, OAQ any additional information identified as being needed to process the application.

B.18 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
Permits Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application shall be certified by the "responsible official" as defined by 326 IAC 2-7-1(34).

(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.19 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 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.20 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),(c), or (e) 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
Permits 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, 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),(c), or (e). 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), (c)(1), and (e)(2).

(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(36)) 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 the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

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

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

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

(f) This condition does not apply to emission trades of SO_2 or NO_X under 326 IAC 21 or 326 IAC 10-4.

B.21 Source Modification Requirement [326 IAC 2-7-10.5]

(a) A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2 and 326 IAC 2-7-10.5.

(b) Any modification at an existing major source is governed by the requirements of 326 IAC 2-2.

B.22 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.23 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
Permits Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The application which shall be submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(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.24 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.25 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 5-1-3 (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 or incinerate any waste or refuse except as provided in 326 IAC 4-2 and 326 IAC 9-1-2.

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 Motor Vehicle Fugitive Dust Sources [326 IAC 6-4-4]

Pursuant to 326 IAC 6-4-4, no vehicle owned or operated by the Permittee shall be driven or moved on any public street, road, alley, highway, or other thoroughfare, unless such vehicle is so constructed as to prevent its contents from dripping, sifting, leaking, or otherwise escaping therefrom so as to create conditions which result in fugitive dust. This section applies only to the cargo any vehicle may be conveying and mud tracked by the vehicle.

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

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted by using ambient air quality modeling pursuant to 326 IAC 1-7-4. The provisions of 326 IAC 1-7-1(3), 326 IAC 1-7-2,

326 IAC 1-7-3(c) and (d), 326 IAC 1-7-4, and 326 IAC 1-7-5(a), (b), and (d) are not federally enforceable.

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

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

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

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

(a) All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this permit, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.

A test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, 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 certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(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 certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

Compliance Requirements [326 IAC 2-1.1-11]

C.10 Compliance Requirements [326 IAC 2-1.1-11]

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

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

C.11 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)]

Unless otherwise specified in this permit, all monitoring and record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance. If required by Section D, the Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. If due to circumstances beyond its control, that equipment cannot be installed and operated within ninety (90) days, 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 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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a source modification shall be implemented when operation begins.

C.12 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment. For a boiler, the COMS shall be in operation in accordance with 326 IAC 3-5 and 40 CFR Part 60 when the boiler draft fan is in operation.

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

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

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

(1) Visible emission readings shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, for a minimum of five (5) consecutive six (6) minute averaging periods beginning not later than twenty-four (24) hours after the start of the malfunction or down time; provided, however, that if such 24-hour period ends during the period beginning two (2) hours before sunset and ending two (2) hours after sunrise, then such visible emissions readings shall begin within four (4) hours of sunrise on the day following the expiration of such 24-hour period.

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

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

(4) Any opacity exceedances determined by Method 9 readings shall be reported with the Quarterly Opacity Exceedances Reports.

(e) The Permittee is required to comply with the requirements to operate a continuous opacity monitoring system pursuant to 326 IAC 3-5, (and 40 CFR 60 and/or 40 CFR 63).

However, operating the COM is not required when performing necessary quality assurance and maintenance activities for the COM and the necessary activity requires the COM to be shut down.

C.13 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

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

(b) 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.

(c) Whenever a continuous emission monitor other than an opacity monitor is malfunctioning or will be down for calibration, maintenance, or repairs for a period of four (4) hours or more, a calibrated backup CEMS shall be brought online within four (4) hours of shutdown of the primary CEMS, and shall be operated until such time as the primary CEMS 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 326 IAC 3-5 and 40 CFR 60.

C.14 Monitoring Methods [326 IAC 3] [40 CFR 60] [40 CFR 63]

Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, 40 CFR 60, Appendix B, 40 CFR 63, or other approved methods as specified in this permit.

C.15 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.

(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.16 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 prepared and submitted written emergency reduction plans (ERPs) consistent with safe operating procedures on.

(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.17 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.18 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) Upon detecting an excursion or exceedance, the Permittee shall 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 emissions.

(b) 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). Corrective actions may include, but are not limited to, the following:

(1) initial inspection and evaluation;

(2) recording that operations returned 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 within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(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 maintain the following records:

(1) monitoring data;

(2) monitor performance data, if applicable; and

(3) corrective actions taken.

C.19 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 take appropriate response actions. The Permittee shall submit a description of these response actions to IDEM, OAQ, within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize excess emissions from the affected facility while the response actions are being implemented.

(b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred twenty (120) 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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

C.20 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]

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

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

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1 (32) ("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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The emission statement 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.21 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2]

(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. 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, all record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance.

(c) If there is a reasonable possibility (as defined in 40 CFR 51.165 (a)(6)(vi)(A), 40 CFR 51.165 (a)(6)(vi)(B), 40 CFR 51.166 (r)(6)(vi)(a), and/or 40 CFR 51.166 (r)(6)(vi)(b)) that a "project" (as defined in 326 IAC 2-2-1(qq) and 326 IAC 2-3-1(ll)) 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(ee) and 326 IAC 2-3-1(z)) and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(rr) and 326 IAC 2-3-1(mm)), the Permittee shall comply with following:

(1) Before beginning actual construction of the “project” (as defined in 326 IAC 2-2-1 (qq)) and/or 326 IAC 2-3-1 (ll) 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(rr)(2)(A)(iii)) and/or 326 IAC 2-3-1(mm)(2)(A)(3); 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 40 CFR 51.165 (a)(6)(vi)(A) and/or 40 CFR 51.166 (r)(6)(vi)(a)) that a “project” (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(ll)) 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(ee) and/or 326 IAC 2-3-1(z)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(rr) and/or 326 IAC 2-3-1(mm)), 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.22 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported. This report shall be submitted within thirty (30) days of the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The report required in (a) of this condition and reports required by conditions in Section D of this permit shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, 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) Unless otherwise specified in this permit, all reports required in Section D of this permit shall be submitted within thirty (30) days of the end of the reporting period. All reports do require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(e) 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.

(f) If the Permittee is required to comply with the recordkeeping provisions of (c) in Section C- General Record Keeping Requirements for any “project” (as defined in 326 IAC 2-2-1 (qq)) and/or 326 IAC 2-3-1 (ll) 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 (xx)) and/or 326 IAC 2-3-1 (qq), 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).

The report for project at an existing emissions unit shall be submitted within 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 (c)(2) and (3) 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 deems fit to include in this report,

Reports required in this part shall be submitted to:

Indiana Department of Environmental Management
Air Compliance Section, 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.

(h) 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.23 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 the standards for recycling and emissions reduction:

(a) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR 82.156.

(b) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

(c) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.

Ambient Monitoring Requirements [326 IAC 7-3]

C.24 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 Unit No. 1, constructed in 1974, with a start up date of 1979, with a design fuel heat input capacity of 2518 million (MM) Btu per hour (nominal HHV), with a fabric filter for control of particulate matter (PM), with a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low -NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with continuous emissions monitoring systems (CEMS) for NOx and SO2 and continuous opacity monitoring (COM) system for opacity and exhausting to stack #1. Natural gas (NG) can be used as an alternate fuel for startup, shutdown, and malfunctions.

Insignificant Activities

(1) Boiler Chemical Cleaning waste evaporation

(3) Facility waste oil incineration

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

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

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

Pursuant to 326 IAC 7-1.1-2(a)(1) (Sulfur Dioxide Emission Limitations), the SO_2 emissions from Boiler No. 1 shall not exceed 6.0 pounds per million Btu (lbs/MMBtu).

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

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

(b) If this facility cannot meet the opacity limitation of 326 IAC 5-1-3(a), the Permittee may submit a written request to IDEM, OAQ, for a temporary alternative opacity limitation in accordance with 326 IAC 5-1-3(e). The Permittee must demonstrate that the alternative limit is needed and justifiable.

D.1.3 Operation Standards [326 IAC 2-1.1-5(a)(4)]

(a) All coal burned, including coal treated with any additive, shall meet ASTM specifications for classification as coal (ASTM D388).

(b) The burning of hazardous waste, as defined by 40 CFR 261, is prohibited in this facility. Any boiler tube chemical cleaning waste liquids evaporated in the boiler, and any binding agent or used oil combusted shall meet the toxicity characteristic requirements for non-hazardous waste.

(c) Used oil generated onsite may be combusted as supplemental fuel for energy recovery in compliance with 40 CFR Part 279 (Standards for the management of used oil) and 329 IAC 13 (Used Oil Management).

(d) Any boiler tube chemical cleaning waste liquids evaporated in the boiler shall only contain the cleaning solution and no more than two full volume boiler rinses.

The requirements in this condition are not federally enforceable pursuant to this Part 70 permit.

D.1.4 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventative Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan of this permit, is required for these facilities and their control devices.

Compliance Determination Requirements

D.1.5 Testing Requirements [326 IAC 2-1.1-11]

In order to determine compliance with PM limitation, the Permittee shall perform PM testing During the second Quarter of 2009 on the fabric filter controlling the dry-bottom pulverized coal-fire boiler, identified as Unit 1 utilizing methods as approved by the Commissioner. This test shall be repeated by the second Quarter of every second year following this valid compliance demonstration. Testing shall be conducted in accordance with Section C- Performance Testing.

D.1.6 Operation of Fabric Filter [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, the fabric filter shall be operated at all times that the boiler is in operation.

D.1.7 Scrubber Operation

Except as otherwise provided by statute or rule or in this permit, the scrubber shall be operated as needed to maintain compliance with all applicable SO_2 emission limits.

D.1.8 Continuous Emissions Monitoring [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) and 40 CFR 60.45, continuous emission monitoring systems for Unit 1 shall be calibrated, maintained, and operated for measuring opacity, SO_2, NO_X, and either CO_2 or O_2 which meets the performance specifications of 326 IAC 3-5-2 and 40 CFR 60.45.

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

D.1.9 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 2-1.1-5(a)(4)]

Pursuant to 326 IAC 7-2-1(a) and (c), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the applicable limits in Condition D.1.1, as established in 326 IAC 7-1.1-2(b). Compliance with this limit shall be determined using SO_2 CEMS data, and demonstrated using a thirty (30) day rolling weighted average.

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

D.1.10 Parametric Monitoring

The Permittee shall monitor the pressure drop across the fabric filter in conjunction with the dry-bottom pulverized coal-fire boiler at least once per day when the dry-bottom pulverized coal-fire boiler is in operation. If the monitoring system malfunctions for more than 8 hours, then the Permittee will manually record the static pressure drop once per day until the monitoring system is operational.

If during any hour of stable boiler operational (excluding hours when a startup, shutdown , or

malfunction is occurring), an hourly average pressure drop is outside the range of established during the latest stack test, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

Any analog instrument used for determining the pressure shall comply with condition C.15 - Instrument Specifications, be subject to approval by IDEM, OAQ, and shall be calibrated at least once every six (6) months.

D.1.11 Broken or Failed Bag Detection

In the event that bag failure has been observed:

(a) For multi-compartment units, the affected compartments will be shut down immediately until the failed units have been repaired or replaced. Within eight (8) business hours of the determination of failure, response steps according to the timetable described in the Response to Excursions or Exceedances shall be initiated. For any failure with corresponding response steps and timetable not described in the Response to Excursions or Exceedances, response steps shall be devised within eight (8) business hours of discovery of the failure and shall include a timetable for completion. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit. If operations continue after bag failure is observed and it will be 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.

(b) For single compartment baghouses, if failure is indicated by a significant drop in the bag's pressure readings with abnormal visible emissions or the failure is indicated by an opacity violation, or if bag failure is determined by other means, such as gas temperatures, flow rates, air infiltration, leaks, dust traces or triboflows, then failed units and the associated process will be shut down immediately until the failed units have been repaired or replaced. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

D.1.12 SO_2 Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

The Permittee shall comply with 40 CFR Part 75, Appendix D, in connection with any downtime for its SO_2 monitor.

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

D.1.13 Record Keeping Requirements

(a) To document compliance with Section C - Maintenance of Continuous Opacity Monitoring Equipment, and the particulate matter and opacity requirements in Conditions D.1.2, D1.8, D.1.5 and D.1.10, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits in Condition D.1.2.

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

(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5-6.

(3) The result of all visible emission (VE) notations and method 9 visible emission reading taken during any periods of COM downtime

(4) All fabric filter parametric monitoring

(b) To document compliance with the SO_2 requirements in Conditions D.1.1, D.1.8, D.1.9 and D.1.12, the Permittee shall maintain records in accordance with (1) through (2) below. Records shall be complete and sufficient to establish compliance with the applicable SO_2 limit(s) as required in Conditions D.1.1 and D.1.8. The Permittee shall maintain records in accordance with (1) and (2) below during SO_2 CEM system downtime.

(1) All SO_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 7-2-1(g), and 40 CFR 60.45.

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

(c) To document compliance with the NO_X requirements in Conditions D.1.8, the Permittee shall maintain records of all NO_X and CO_2 or O_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6 and 40 CFR 60.45. Records shall be complete and sufficient to establish compliance with the NO_X limit as required in Condition D.1.8.

(d) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.1.14 Record Keeping Requirement

(a) A quarterly report of opacity exceedances and a quarterly summary of the information to document compliance with Conditions D.1.1 and D.1.2, shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

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

(1) Date of downtime;

(2) Time of commencement;

(3) Duration of each downtime;

(4) Reasons for each downtime; and

(5) Nature of system repairs and adjustments.

The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

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

Insignificant Activities

(1) Boiler Chemical Cleaning waste evaporation

(3) Facility waste oil incineration

(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 Minor Limits [326 IAC 2-2]

Pursuant to PSD (65) 1355 issued on February 22, 1979, the emission rates from Unit 2 shall not exceed the following:

(a) Particulate matter (PM) - 0.03 pounds per million Btu (MMBtu) of energy input.

(b) Sulfur dioxide - 0.69 pounds per million Btu (MMBtu) of energy input.

(c) Nitrogen oxides - 0.6 pounds per million Btu (MMBtu) of energy input.

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

Pursuant to PSD (65) 1355 issued on February 22, 1979, “Best Available Control Technology” (BACT) emission controls shall be used for Unit 2 as follows:

(a) Sulfur dioxide shall be controlled by a scrubber having a minimum control efficiency of 90.0%.

(b) The stack gas particulate emissions shall be controlled by an electrostatic precipitator having a minimum collection efficiency of 99.6% when burning coal with a maximum ash content of 10%, a minimum sulfur content of 2.5% and a minimum heat content of 11,000 Btu’s per pound.

D.2.3 Sulfur Dioxide (SO2) [326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-1.1-2(a)(1) (Sulfur Dioxide Emission Limitations), the SO_2 emissions from Boiler No. 2 shall not exceed 6.0 pounds per million Btu (lbs/MMBtu).

D.2.4 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

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

(b) If this facility cannot meet the opacity limitation of 326 IAC 5-1-3(a), the Permittee may submit a written request to IDEM, OAQ, for a temporary alternative opacity limitation in accordance with 326 IAC 5-1-3(e). The Permittee must demonstrate that the alternative limit is needed and justifiable.

D.2.5 Operation Standards [326 IAC 2-1.1-5(a)(4)] [40 CFR 261] [40 CFR 279] [329 IAC 13]

(a) All coal burned, including coal treated with any additive, shall meet ASTM specifications for classification as coal (ASTM D388).

(b) Any boiler tube chemical cleaning waste liquids evaporated in the boiler shall only contain the cleaning solution and no more than two full volume boiler rinses.

The requirements in this condition are not federally enforceable pursuant to this Part 70 permit.

D.2.6 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventative Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan of this permit, is required for these facilities and their control devices.

Compliance Determination Requirements

D.2.7 Testing Requirements [326 IAC 2-1.1-11] [40 CFR 60 Subpart Da]

In order to determine compliance with Conditions D.2.1 and D.2.2, the Permittee shall perform PM testing during the second Quarter of 2010 on the electrostatic precipitator (ESP) controlling the dry-bottom pulverized coal-fire boiler, identified as Unit 2 utilizing methods as approved by the Commissioner. This test shall be repeated by the second Quarter of every second year following this valid compliance demonstration. Testing shall be conducted in accordance with Section C - Performance Testing.

D.2.8 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 (ESP) shall be in operation at all times that the boiler vented to the ESP is in operation and combusting coal, except during periods of startup, shutdown, or emergency as described in Section B - Emergency Provisions.

D.2.9 Scrubber Operation

Except as otherwise provided by statute or rule or in this permit, the scrubber shall be operated as needed to maintain compliance with all applicable SO_2 emission limits.

D.2.10 Continuous Emissions Monitoring [326 IAC 3-5]

(a) Pursuant to PSD (65) 1355 issued on February 22, 1979 and 326 IAC 2-2, in-stack continuous emission monitoring systems shall be calibrated, maintained, and operated for measuring opacity, SO_2, NO_X, and either CO_2 or O_2, which meet the performance specifications of 326 IAC 3-5-2.

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

D.2.11 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 2-1.1-5(a)(4)]

Pursuant to 326 IAC 7-2-1(a) and (c), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the applicable limits in Condition D.2.3, as established in 326 IAC 7-1.1-2(b). Compliance with this limit shall be determined using SO_2 CEMS data, and demonstrated using a thirty (30) day rolling weighted average.

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

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

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

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

D.2.13 SO_2 Monitoring System Downtime [326 IAC 2-2] [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

Whenever the SO_2 continuous emission monitoring system is malfunctioning or down for repairs or adjustments, the Permittee shall monitor and record boiler load, recirculation pH, valve position, and absorber level to demonstrate that the operation of the scrubber continues in a manner typical for the boiler load and sulfur content of the coal fired. Scrubber parametric monitoring readings shall be recorded at least one (1) time per hour until the primary CEM or a backup CEM is brought online.

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

D.2.14 Record Keeping Requirement

(a) To document compliance with Section C - Maintenance of Continuous Opacity Monitoring Equipment, and the particulate matter and opacity requirements in Conditions D.2.1, D.2.2, D.2.7, D.2.10, and D.2.12, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits in Conditions D.2.1 and D.2.2.

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

(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5-6 and 40 CFR 60.49a.

(3) The result of all visible emission (VE) notations and method 9 visible emission reading taken during any periods of COM downtime

(4) All ESP Parametric monitoring readings.

The Permittee shall not be required to comply with Subpart (a)(4) regarding ESP parametric monitoring reading until March 1, 2007.

(b) To document compliance with SO_2 Conditions D.2.1(b), D.2.2, D.2.3, D.2.10, D.2.11 and D.2.13, the Permittee shall maintain records in accordance with (1) through (2) below. Records shall be complete and sufficient to establish compliance with the SO_2 limit(s) as

required in Conditions D.2.1(b), D.2.3 and D.2.10. The Permittee shall maintain records in accordance with (1) and (2) below during SO_2 CEM system downtime.

(1) All SO_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 7-2-1(g) and/or 40 CFR 60.49a.

(2) All scrubber parametric monitoring readings taken during any periods of CEM downtime, in accordance with Condition D.2.16.

(c) To document compliance with NO_X Conditions D.2.1(c) and D.2.11, the Permittee shall maintain records of all NO_X and CO_2 or O_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 2-2 and 40 CFR 60.49a. Records shall be complete and sufficient to establish compliance with the NO_X limits as required in Conditions D.2.1(c) and D.2.11.

(e) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.2.15 Reporting Requirements

(a) A quarterly report of opacity exceedances and a quarterly summary of the information to document compliance with Condition D.2.1 shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(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(34).

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) One (1) simple-cycle, natural gas-fired combustion turbine, designated as unit ABB CT No. 3, with constructed in 1991, with a design fuel heat input capacity of 897.4 million Btu per hour (nominal LHV), utilizing distillate oil (No. 2 fuel oil) as a backup fuel, with a water injection system for control of NO_X emissions, with a continuous emissions monitoring (CEM) system for nitrogen oxides (NO_X) and exhausting to stack #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.3.1 PSD Minor Limits [326 IAC 2-2]

Pursuant to Construction Permit PC (65) 1802, issued on November 6, 1989, and 326 IAC 2-2-1 (PSD Requirements), the following limitations and standards shall be met:

(a) In order to make the requirements of 326 IAC 2-2-1(x) and 326 IAC 2-2-1(jj) (PSD Requirements) not applicable to ABB CT No. 3, the nitrogen oxides (NO_X) emissions from ABB CT No. 3 shall be limited to less than 40 tons per twelve (12) consecutive month period, and the sulfur dioxide (SO_2) emissions from ABB CT No. 3 shall be limited to less than 40 tons per twelve (12) consecutive month period, with Compliance determined at the end of each month period.

(b) Natural gas shall be used as the primary fuel for this turbine. No. 2 distillate fuel oil shall be used as an emergency backup fuel only. Pursuant to 40 CFR 60.331(r), emergency fuel is defined as a fuel fired by a gas turbine only during circumstances such as natural gas curtailment or breakdown of delivery system that make it impossible to fire natural gas in the turbine. The quantity of No. 2 distillate fuel oil used shall not exceed 1,893,000 gallons per twelve (12) consecutive month period, with compliance determined at the end of each month and the SO_2 and NOx emissions shall not exceed 0.042 pounds per gal each.

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

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

Pursuant to 326 IAC 7-1.1-2, the sulfur dioxide emissions from the turbine, identified as ABB Unit No. 3 shall be limited to 0.5 pounds per million Btu when firing distillate oil, the backup fuel.

D.3.3 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 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 in a six (6) hour period.

D.3.4 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventative Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan of this permit, is required for these facilities and their control devices.

Compliance Determination Requirements

D.3.5 Continuous Emission Monitoring [326 IAC 3-5]

(a) The Permittee shall calibrate, certify, operate and maintain a continuous emissions monitoring system for combustion turbine ABB CT No.3 stack #3 for NO_X and CO_2 or O_2 in accordance with 326 IAC 3-5-2 through 3-5-7.

(b) The Permittee shall determine compliance with the NO_X limit in Condition D.3.1 utilizing data from the NO_X and CO_2 or O_2 CEMS.

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

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

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

D.3.6 Visible Emissions Notations

(a) When fuel oil is being fired, visible emission notations of the ABB CT NO.3 stack exhaust shall be performed once per day during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

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

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

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

(e) If abnormal emissions are observed, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances shall be considered a deviation from this permit.

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

D.3.7 Record Keeping Requirement

(a) To document compliance with Condition D.3.1, the Permittee shall maintain records of the following:

(1) Date and times for all periods of turbine operation.

(2) All NO_X continuous emissions monitoring data, pursuant to 326 IAC 3-5-6.

(3) Amount of distillate oil combusted (in kgal) in the turbine during each month.

(b) To document compliance with Conditions D.3.1 and D.3.2, the source shall maintain records of the natural gas analyses, including the sulfur and nitrogen content of the gas. These records shall include:

(1) The full quarterly gas analysis results.

(2) The location where the samples were taken.

(c) To document compliance with Conditions D.3.1, D.3.2 and D.3.5, the source shall maintain records of the distillate oil analyses, including the sulfur content of the oil.

(d) To document compliance with Condition D.3.6 - Visible Emission Notation, the Permittee shall maintain daily records of the visible emission notations of the dry-bottom pulverized coal-fire boiler stack exhaust. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that day).

(e) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this approval.

D.3.8 Reporting Requirements

(a) A quarterly summary of the information to document compliance with the NO_X emission limit of Condition D.3.1 shall be submitted to the address listed in Section C - General Reporting Requirements, of this approval, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(b) A quarterly summary of the information to document compliance with the distillate oil use limit of Condition D.3.1(b)shall be submitted to the address listed in Section C - General Reporting Requirements, of this approval, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) One (1) simple cycle natural gas-fired combustion turbine, designated as unit ABB No. 4, with constructed 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV) with inlet fogger for power augmentation during high ambient temperature operation, with dry low-NOx combustion, with continuous emissions monitoring (CEM) system for nitrogen oxides (NO_X) and carbon monoxide (CO), exhausting to stack No.4

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

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

D.4.1 PM10 PSD BACT [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD BACT) and Significant Source Mod 129-14021-00001, issued November 16, 2001, the PM_{10} emissions from ABB No. 4 shall comply with the following:

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

(b) Perform good combustion.

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

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

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

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

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

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

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

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

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

(b) Pursuant to 326 IAC 2-2 (PSD Requirements) and Significant Source Mod 129-14021-00001, the annual CO emissions from ABB No. 4 burning natural gas shall be less than

221.52 tons per twelve (12) consecutive month period, excluding startup and shutdown emissions, with compliance determined at the end of each month.

D.4.4 Startup and Shutdown Limitations for Combustion Turbines

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

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

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

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

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

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

D.4.5 Hazardous Air Pollutants (HAP) Limitations

Pursuant to Significant Source Mod 129-14021-00001, issued November 16, 2001, the formaldehyde emissions from the ABB No. 4 combustion turbine shall not exceed 0.00142 lb/MMBtu. This will limit the formaldehyde emissions from ABB No. 4 below 10 tons per year and make requirements of 326 IAC 2-4.1 not applicable.

D.4.6 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventative Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan of this permit, is required for these facilities and their control devices.

Compliance Determination Requirements

D.4.7 Continuous Emission Monitoring [326 IAC 2-2] [326 IAC 3-5]

(a) The Permittee shall calibrate, certify, operate and maintain a continuous emissions monitoring system for combustion turbine ABB No.4 stack #4 for NO_X, CO, and CO_2 or O_2 in accordance with 326 IAC 3-5-2 through 3-5-7.

(1) The continuous emission monitoring system (CEMS) shall measure NO_X and CO emissions rates in pounds per hour, uncorrected parts per million, and parts per million on a dry volume basis (ppmvd) corrected to 15% O2. The use of CEMS to measure and record the NO_X and CO hourly limits, is sufficient to demonstrate compliance with the limitations established in the BACT analysis and set forth in the permit. To demonstrate compliance with the NO_X limit, the source shall take an average of the ppmvd corrected to 15% O_2 over a twenty four (24) operating hour averaging period. To demonstrate compliance with the CO limit, the source shall take an average of the ppmvd corrected to 15% O_2 over a twenty four (24)

hour operating period. The source shall maintain records of the ppmvd corrected to 15% O_2 and the pounds per hour.

(2) The Permittee shall determine compliance with Condition D.4.4 utilizing data from the NO_X, CO, and CO_2 or O_2 CEMS, and the fuel flow meter, and Method 19 calculations.

(3) The Permittee shall submit to IDEM, OAQ within ninety (90) days after monitor installation, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.

(4) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7.

(b) The Permittee shall follow parametric monitoring requirements for determining SO_2 emissions contained in the "Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil Fired Units" in lieu of continuous emissions monitors (CEMS).

(1) Pursuant to the procedures contained in 40 CFR 75.20, the Permittee shall complete all testing requirements to certify the use of the "Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil Fired Units" protocol.

(2) The Permittee shall apply to IDEM for initial certification to use the "Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil Fired Units" protocol, no later than 45 days after the compliance of all certification tests.

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

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

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

D.4.8 Record Keeping Requirement

(a) To document compliance with Condition D.4.1, the Permittee shall maintain records of the following:

(1) Amount of natural gas combusted (in MMCF) during each month;

(2) The percent sulfur content of the natural gas; and

(3) The average heat content, on a higher heating value basis.

(b) To document compliance with Conditions D.4.2 and D.4.3, the Permittee shall maintain records of the emission rates of NO_X and CO in pounds per hour and ppmvd corrected to 15% oxygen.

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

(1) The type of operation (i.e., startup or shutdown) with supporting operational data;

(2) The total number of minutes for startup or shutdown per 24-hour period per turbine; and

(3) The CEMS data and fuel flow meter data corresponding to each startup and shutdown period.

(d) To document compliance with Condition D.4.7 - Continuous Emission Monitoring, the Permittee shall maintain records, including raw data of all monitoring data and supporting information, for a minimum of five (5) years from the date as described in 326 IAC 3-5-7(a). The records shall include the information described in 326 IAC 3-5-7(b).

(f) All records shall be maintained in accordance with Section C – General Record Keeping Requirements, of this permit

D.4.9 Reporting Requirements

(1) Records of excess NO_X and CO emissions (defined in 326 IAC 3-5-7 and 40 CFR Part 60.7) from the continuous emissions monitoring system. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C – General Reporting Requirements of this permit.

(2) A quarterly summary of the CEMS data to document compliance with Conditions D.4.2 and D.4.3, shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(3) A quarterly summary of the total number of startup and shutdown events to document compliance with Condition D.4.4 shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported, using the reporting form located at the end of this permit, or its equivalent. The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(e) A coal storage and handling system, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit 2 boiler, with a maximum throughput of 600 tons of coal per hour, consisting of the following equipment:

(1) One (1) railcar and truck unloading station with particulate emissions controlled by enclosure, with a drop point to the coal pile.

(2) One (1) storage pile, having a storage capacity of 700,000 tons, with fugitive emissions controlled by a watering system.

(3) An enclosed conveyor system, with a maximum feed rate of 600 tons per hour, with the transfer points underground or enclosed by buildings, and exhausting inside the transfer buildings or powerhouse.

(4) Twelve (12) enclosed coal pulverizers, each with a maximum capacity of twenty (20) tons of coal per hour, and exhausting to the boilers

Insignificant Activities

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

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

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

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

Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes) the coal storage and handling system operating at a process weight rate of 600 tons per hour, the concentration of particulate in discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1000) pounds of gases.

D.5.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventative Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan of this permit, is required for these facilities and their control devices.

Compliance Determination Requirements

D.5.3 Particulate Matter (PM) Control

Inorder to comply with Condition D.5.1, the water mist curtain for particulate control shall be in operation and control emissions from the railcar and truck unloading station at all times when the railcar and truck unloading station is in operation unless there is adequate atmospheric precipitation to control emissions or unless the coal is so damp as to control emissions.

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

D.5.4 Visible Emission Notations

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

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

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

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

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

(f) If abnormal emissions are observed, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances shall be considered a deviation from this permit.

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

D.5.5 Record Keeping Requirement

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

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

(c) Beginning on March 1, 2007 and thereafter, the visible emission notation records for the railcar and truck unloading station performed under Condition D.5.4 also shall identify:

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

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

(d) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(f) A lime storage and handling system, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit 2 boiler, consisting of the following equipment:

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

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

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

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

(g) A soda ash storage and handling system, consisting of the following equipment:

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

(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 lime storage and soda ash storage handling system shall not exceed the amounts determined by the following:

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

$E = 4.10\ P^{0.67}$ where E = rate of emission in pounds per hour and
P = process weight rate in tons per hour

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

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

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

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

A Preventative Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan of this permit, is required for these facilities and their control devices.

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

D.6.3 Visible Emissions Notations

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

(b) Visible emission notations of the soda ash handling exhaust shall be performed once per day during normal daylight operations when transferring soda ash. A trained employee shall record whether emissions are normal or abnormal.

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

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

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

(f) If abnormal emissions are observed, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances shall be considered a deviation from this permit.

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

D.6.4 Record Keeping Requirement

(a) To document compliance with Condition D.6.3 - Visible Emission Notations, the Permittee shall maintain daily records of visible emission notations of the lime transfer point and the soda ash handling exhausts. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).

(b) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

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

(i) Scrubber sludge handling, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit 2 boiler, with wet sludge conveyed to haul trucks.

Insignificant Activities

(2) Ash pond and ash pond maintenance, with water cover or vegetation sufficient to prevent ash re-entrainment.

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

A Preventative Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan of this permit, is required for these facilities and their control devices.

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

D.7.2 Visible Emissions Notations

(a) Visible emission notations of the fly ash storage pond areas shall be performed once per week during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

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

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

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

(e) If abnormal emissions are observed, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances shall be considered a deviation from this permit.

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

D.7.3 Record Keeping Requirement

(a) To document compliance with Condition D.7.2, the Permittee shall maintain weekly records of visible emission notations of the fly ash storage pond areas. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that week).

(b) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activities

(a) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6.[326 IAC 8-3-2] [326 IAC 8-3-5].

(d) The following equipment related to manufacturing activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

(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 Organic Solvent Degreasing Operations: Cold Cleaner Operations [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-2 (Cold Cleaner Operation), for cold cleaning facilities constructed after January 1, 1980, the Permittee shall:

(a) Equip the cleaner with a cover;

(b) Equip the cleaner with a emissions unit for draining cleaned parts;

(c) Close the degreaser cover whenever parts are not being handled in the cleaner;

(d) Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases;

(e) Provide a permanent, conspicuous label summarizing the operation requirements;

(f) Store waste solvent only in covered containers and not dispose of waste solvent or transfer it to another party, in such a matter that greater than twenty percent (20%) of the waste solvent (by weight) can evaporate into the atmosphere.

D.8.2 Organic Solvent Degreasing Operations: Cold Cleaner Operation and Control [326 IAC 8-3-5]

(a) Pursuant to 326 IAC 8-3-5(a) (Cold Cleaner Degreaser Operation and Control), for cold cleaner degreaser operations without remote solvent reservoirs constructed after July 1, 1990, the Permittee shall ensure that the following control equipment requirements are met:

(1) Equip the degreaser with a cover. The cover must be designed so that it can be easily operated with one (1) hand if:

(A) The solvent volatility is greater than two (2) kiloPascals (fifteen (15) millimeters of mercury or three-tenths (0.3) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F));

(B) The solvent is agitated; or

(C) The solvent is heated

(2) Equip the degreaser with a emissions unit for draining cleaned articles. If the solvent volatility is greater than four and three-tenths (4.3) kiloPascals (thirty-two

(32) millimeters of mercury) or six-tenths (0.6) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F)), then the drainage emissions unit must be internal such that articles are enclosed under the cover while draining. The drainage emissions unit may be external for applications where an internal type cannot fit into the cleaning system.

(3) Provide a permanent, conspicuous label which lists the operating requirements outlined in subsection (b).

(4) The solvent spray, if used, must be a solid, fluid stream and shall be applied at a pressure which does not cause excessive splashing.

(5) Equip the degreaser with one (1) of the following control devices if the solvent volatility is greater than four and three-tenths (4.3) kiloPascals (thirty-two (32) millimeters of mercury) or six-tenths (0.6) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F)), or if the solvent is heated to a temperature greater than forty-eight and nine-tenths degrees Celsius (48.9^{O}C) (one hundred twenty degrees Fahrenheit (120°F)):

(A) A freeboard that attains a freeboard ratio of seventy-five hundredths (0.75) or greater.

(B) A water cover when solvent is used is insoluble in, and heavier than, water.

(C) Other systems of demonstrated equivalent control such as a refrigerated chiller of carbon adsorption. Such systems shall be submitted to the U.S. EPA as a SIP revision.

(b) Pursuant to 326 IAC 8-3-5(b) (Cold Cleaner Degreaser Operation and Control), the Permittee shall ensure that the following operating requirements are met:

(1) Close the cover whenever articles are not being handled in the degreaser.

(2) Drain cleaned articles for at least fifteen (15) seconds or until dripping ceases.

(3) Store waste solvent only in covered containers and prohibit the disposal or transfer of waste solvent in any manner in which greater than twenty percent (20%) of the waste solvent by weight could evaporate.

D.8.3 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2, the particulate emissions from the insignificant activities, brazing equipment, cutting torches, soldering equipment, and welding equipment shall be limited by the following equation:

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

$$E = 4.10\ P^{0.67}$$

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

SECTION E.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

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

(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 General Provision Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the dry bottom, pulverized coal-fired boiler, identified as Unit No. 1 except as otherwise specified in 40 CFR Part 60, Subpart D.

(b) Pursuant to 40 CFR 60.10, the Permittee shall submit all required notifications and reports to:
Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue,
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.1.2 Standard of Performance for Fossil-Fuel-Fired Steam Generator for Which Construction is Comenced After August 17, 1971 [326 IAC 12-1] [40 CFR 60, Subpart D]

Pursuant to 40 CFR 60 Subpart D, the Permittee shall comply with the provisions of Standard of Performance for Fossil-Fuel-Fired Steam Generator for Which Construction is Commenced After August 17, 1971 for the dry bottom, pulverized coal-fired boiler, identified as Unit No. 1 as specified as follows:

(1) 40 CFR 60.40
(2) 40 CFR 60.41
(3) 40 CFR 60.42
(4) 40 CFR 60.43
(5) 40 CFR 60.44
(6) 40 CFR 60.45
(7) 40 CFR 60.46

SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

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

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

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the dry bottom, pulverized coal-fired boiler, identified as Unit No. 2 except as otherwise specified in 40 CFR Part 60, Subpart Da.

(b) Pursuant to 40 CFR 60.10, the Permittee shall submit all required notifications and reports to:
Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue,
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.2.2 Standard of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 [326 IAC 12-1] [40 CFR 60, Subpart Da]

Pursuant to 40 CFR 60 Subpart Da, the Permittee shall comply with the provisions of Standard of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978, for the dry bottom, pulverized coal-fired boiler, identified as Unit No. 2 as specified as follows:

(1) 40 CFR 60.40da
(2) 40 CFR 60.41da
(3) 40 CFR 60.42da
(4) 40 CFR 60.43da
(5) 40 CFR 60.44da
(6) 40 CFR 60.45da
(7) 40 CFR 60.46da
(8) 40 CFR 60.47da
(9) 40 CFR 60.48da
(10) 40 CFR 60.49da
(11) 40 CFR 60.50da
(12) 40 CFR 60.51da

(13) 40 CFR 60.52da

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

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

(d) One (1) simple cycle natural gas-fired combustion turbine, designated as unit ABB No. 4, with constructed 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV) with inlet fogger for power augmentation during high ambient temperature operation, with dry low-NOx combustion, with continuous emissions monitoring (CEM) system for nitrogen oxides (NO_X) and carbon monoxide (CO), exhausting to stack No.4.

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

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the simply-cycle, identified as ABB CT No.3 and turbine generator, identified as Unit ABB No.4 except as otherwise specified in 40 CFR Part 60, Subpart GG.

(b) Pursuant to 40 CFR 60.10, the Permittee shall submit all required notifications and reports to:
Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue,
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.3.2 Standard of Performance for Stationary Gas Turbines [326 IAC 12-1] [40 CFR 60, Subpart GG]

Pursuant to 40 CFR 60 Subpart GG, the Permittee shall comply with the provisions of Standard of Performance for Stationary Gas Turbines for the simply-cycle, identified as ABB CT No.3 and turbine generator, identified as Unit ABB No.4 as specified as follows:

(1) 40 CFR 60.330
(2) 40 CFR 60.331
(3) 40 CFR 60.332
(4) 40 CFR 60.333
(5) 40 CFR 60.334
(6) 40 CFR 60.335

SECTION E.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

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

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

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

(d) One (1) simple cycle natural gas-fired combustion turbine, designated as unit ABB No. 4, with constructed 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV) with inlet fogger for power augmentation during high ambient temperature operation, with dry low-NOx combustion, with continuous emissions monitoring (CEM) system for nitrogen oxides (NO_X) and carbon monoxide (CO), exhausting to stack No.4.

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

Acid Rain Program

E.4.1 Acid Rain Permit [326 IAC 2-7-5(1)(C)] [326 IAC 21] [40 CFR 72 through 40 CFR 78]

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

E.4.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)] [326 IAC 21]

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

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

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

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

SECTION F Nitrogen Oxides Budget Trading program - NOx Budget Permit for NOx Budget unit Units Under 326 IAC 10-4-1(a)

ORIS Code: 6137

NOx Budget Source [326 IAC 2-7-5(15)]:

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

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

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

(d) One (1) simple cycle natural gas-fired combustion turbine, designated as unit ABB No. 4, with constructed 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV) with inlet fogger for power augmentation during high ambient temperature operation, with dry low-NOx combustion, with continuous emissions monitoring (CEM) system for nitrogen oxides (NO_X) and carbon monoxide (CO), exhausting to stack No.4.

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

F.1 Automatic Incorporation of Definitions [326 IAC 10-4-7(e)]

This NO_X budget permit is deemed to incorporate automatically the definitions of terms under 326 IAC 10-4-2.

F.2 Standard Permit Requirements [326 IAC 10-4-4(a)]

(a) The Permittee of the NO_X budget source and each NO_X budget unit shall operate each unit in compliance with this NO_X budget permit.

(b) The NO_X budget units subject to this NO_X budget permit are Unit No. 1, Unit No. 2, ABB CT No. 3, and ABB No. 4.

F.3 Monitoring Requirements [326 IAC 10-4-4(b)]

(a) The Permittee and, to the extent applicable, the NO_X authorized account representative of the NO_X budget source and each NO_X budget unit at the source shall comply with the monitoring requirements of 40 CFR 75 and 326 IAC 10-4-12.

(b) The emissions measurements recorded and reported in accordance with 40 CFR 75 and 326 IAC 10-4-12 shall be used to determine compliance by each unit with the NO_X budget emissions limitation under 326 IAC 10-4-4(c) and Condition F.4, Nitrogen Oxides Requirements.

F.4 Nitrogen Oxides Requirements [326 IAC 10-4-4(c)]

(a) The Permittee of the NO_X budget source and each NO_X budget unit at the source shall hold NO_X allowances available for compliance deductions under 326 IAC 10-4-10(j), as of the NO_X allowance transfer deadline, in each unit's compliance account and the source's overdraft account in an amount:

(1) Not less than the total NO_X emissions for the ozone control period from the unit, as determined in accordance with 40 CFR 75 and 326 IAC 10-4-12;

(2) To account for excess emissions for a prior ozone control period under 326 IAC 10-4-10(k)(5); or

(3) To account for withdrawal from the NO_X budget trading program, or a change in regulatory status of a NO_X budget opt-in unit.

(b) Each ton of NO_X emitted in excess of the NO_X budget emissions limitation shall constitute a separate violation of the Clean Air Act (CAA) and 326 IAC 10-4.

(c) Each NO_X budget unit shall be subject to the requirements under (a) above and 326 IAC 10-4-4(c)(1) starting on May 31, 2004.

(d) NO_X allowances shall be held in, deducted from, or transferred among NO_X allowance tracking system accounts in accordance with 326 IAC 10-4-9 through 11, 326 IAC 10-4-13, and 326 IAC 10-4-14.

(e) A NO_X allowance shall not be deducted, in order to comply with the requirements under (a) above and 326 IAC 10-4-4(c)(1), for an ozone control period in a year prior to the year for which the NO_X allowance was allocated.

(f) A NO_X allowance allocated under the NO_X budget trading program is a limited authorization to emit one (1) ton of NO_X in accordance with the NO_X budget trading program. No provision of the NO_X budget trading program, the NO_X budget permit application, the NO_X budget permit, or an exemption under 326 IAC 10-4-3 and no provision of law shall be construed to limit the authority of the U.S. EPA or IDEM, OAQ to terminate or limit the authorization.

(g) A NO_X allowance allocated under the NO_X budget trading program does not constitute a property right.

(h) Upon recordation by the U.S. EPA under 326 IAC 10-4-10, 326 IAC 10-4-11, or 326 IAC 10-4-13, every allocation, transfer, or deduction of a NO_X allowance to or from each NO_X budget unit's compliance account or the overdraft account of the source where the unit is

located is deemed to amend automatically, and become a part of, this NO_X budget permit of the NO_X budget unit by operation of law without any further review.

F.5 Excess Emissions Requirements [326 IAC 10-4-4(d)]

The Permittee of each NO_X budget unit that has excess emissions in any ozone control period shall do the following:

(a) Surrender the NO_X allowances required for deduction under 326 IAC 10-4-10(k)(5).

(b) Pay any fine, penalty, or assessment or comply with any other remedy imposed under 326 IAC 10-4-10(k)(7).

F.6 Record Keeping Requirements [326 IAC 10-4-4(e)] [326 IAC 2-7-5(3)]

Unless otherwise provided, the Permittee of the NO_X budget source and each NO_X budget unit at the source shall keep, either on site at the source or at a central location within Indiana for those Permittee with unattended sources, each of the following documents for a period of five (5) years:

(a) The account certificate of representation for the NO_X authorized account representative for the source and each NO_X budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with 326 IAC 10-4-6(h). The certificate and documents shall be retained either on site at the source or at a central location within Indiana for those Permittee with unattended sources beyond the five (5) year period until the documents are superseded because of the submission of a new account certificate of representation changing the NO_X authorized account representative.

(b) All emissions monitoring information, in accordance with 40 CFR 75 and 326 IAC 10-4-12, provided that to the extent that 40 CFR 75 and 326 IAC 10-4-12 provide 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 NO_X budget trading program.

(d) Copies of all documents used to complete a NO_X budget permit application and any other submission under the NO_X budget trading program or to demonstrate compliance with the requirements of the NO_X budget trading program.

This period may be extended for cause, at any time prior to the end of five (5) years, in writing by IDEM, OAQ or the U.S. EPA. Records retained at a central location within Indiana shall be available immediately at the location and submitted to IDEM, OAQ or U.S. EPA within three (3) business days following receipt of a written request. Nothing in 326 IAC 10-4-4(e) shall alter the record retention requirements for a source under 40 CFR 75. Unless otherwise provided, all records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

F.7 Reporting Requirements [326 IAC 10-4-4(e)]

(a) The NO_X authorized account representative of the NO_X budget source and each NO_X budget unit at the source shall submit the reports and compliance certifications required under the NO_X budget trading program, including those under 326 IAC 10-4-8, 326 IAC 10-4-12, or 326 IAC 10-4-13.

(b) Pursuant to 326 IAC 10-4-4(e) and 326 IAC 10-4-6(e)(1), each submission shall include the following certification statement by the NO_X authorized account representative: "I am authorized to make this submission on behalf of the Permittee of the NO_X budget sources or NO_X budget 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 10-4 requires a submission to IDEM, OAQ, the NO_X authorized account representative shall submit required information to:

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

(d) Where 326 IAC 10-4 requires a submission to U.S. EPA, the NO_X authorized account representative shall submit required information to:

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

F.8 Liability [326 IAC 10-4-4(f)]

The Permittee of each NO_X budget source shall be liable as follows:

(a) Any person who knowingly violates any requirement or prohibition of the NO_X budget trading program, a NO_X budget permit, or an exemption under 326 IAC 10-4-3 shall be subject to enforcement pursuant to applicable state or federal law.

(b) Any person who knowingly makes a false material statement in any record, submission, or report under the NO_X budget trading program shall be subject to criminal enforcement pursuant to the applicable state or federal law.

(c) No permit revision shall excuse any violation of the requirements of the NO_X budget trading program that occurs prior to the date that the revision takes effect.

(d) Each NO_X budget source and each NO_X budget unit shall meet the requirements of the NO_X budget trading program.

(e) Any provision of the NO_X budget trading program that applies to a NO_X budget source, including a provision applicable to the NO_X authorized account representative of a NO_X budget source, shall also apply to the Permittee of the source and of the NO_X budget units at the source.

(f) Any provision of the NO_X budget trading program that applies to a NO_X budget unit, including a provision applicable to the NO_X authorized account representative of a NO_X budget unit, shall also apply to the owners and operators of the unit. Except with regard to the requirements applicable to units with a common stack under 40 CFR 75 and 326 IAC 10-4-12, the Permittee and the NO_X authorized account representative of one (1) NO_X budget unit shall not be liable for any violation by any other NO_X budget unit of which they

are not Permittee or the NO_X authorized account representative and that is located at a source of which they are not Permittee or the NO_X authorized account representative.

F.9 Effect on Other Authorities [326 IAC 10-4-4(g)]

No provision of the NO_X budget trading program, a NO_X budget permit application, a NO_X budget permit, or an exemption under 326 IAC 10-4-3 shall be construed as exempting or excluding the Permittee and, to the extent applicable, the NO_X authorized account representative of a NO_X budget source or NO_X budget unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the CAA.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
PART 70 OPERATING PERMIT
CERTIFICATION

Source Name:	Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
Source Address:	8511 Welborn Road,, Mount Vernon47620, Indiana
Mailing Address:	20 Northwest Fourth Street, Evansville, IN 47741
Part 70 Permit No.:	T129-26415-00010

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify)

☐ Report (specify)

☐ Notification (specify)

☐ Affidavit (specify)

☐ Other (specify)

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
Signature:
Printed Name:
Title/Position:
Phone:
Date:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE 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: Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
Source Address: 8511 Welborn Road,, Mount Vernon47620, Indiana
Mailing Address: 20 Northwest Fourth Street, Evansville, IN 47741
Part 70 Permit No.: T129-26415-00010

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

☐ This is an emergency as defined in 326 IAC 2-7-1(12) • The Permittee must notify the Office of Air Quality (OAQ), within four (**4**) 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: _____

A certification is not required for this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

PART 70 OPERATING PERMIT
SEMI-ANNUAL NATURAL GAS FIRED BOILER CERTIFICATION

Source Name: Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
Source Address: 8511 Welborn Road,, Mount Vernon47620, Indiana
Mailing Address: 20 Northwest Fourth Street, Evansville, IN 47741
Part 70 Permit No.: T129-26415-00010

☐ Natural Gas Only ☐ Alternate Fuel burned From:_____ To:_____

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:

A certification by the responsible official as defined by 326 IAC 2-7-1(34) is required for this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
Source Address: 8511 Welborn Road,, Mount Vernon47620, Indiana
Mailing Address: 20 Northwest Fourth Street, Evansville, IN 47741
Part 70 Permit No.: T129-26415-00010
Facility: Turbine ABB CT No 3
Parameter: NOx
Limit: Less than 40 tons per twelve (12) consecutive month period

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

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

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
Source Address: 8511 Welborn Road,, Mount Vernon47620, Indiana
Mailing Address: 20 Northwest Fourth Street, Evansville, IN 47741
Part 70 Permit No.: T129-26415-00010
Facility: Turbine ABB CT No 3
Parameter: SO2
Limit: Less than 40 tons per twelve (12) consecutive month period

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

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

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
Source Address: 8511 Welborn Road,, Mount Vernon47620, Indiana
Mailing Address: 20 Northwest Fourth Street, Evansville, IN 47741
Part 70 Permit No.: T129-26415-00010
Facility: Turbine ABB CT No. 3
Parameter: SO2
Limit: Less than 1,893,000 gallon per twelve (12) consecutive month period

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

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

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Quarterly Report

Source Name: Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
Source Address: 8511 Welborn Road,, Mount Vernon47620, Indiana
Mailing Address: 20 Northwest Fourth Street, Evansville, IN 47741
Part 70 Permit No.: T129-26415-00010
Facility: Turbine ABB No. 4
Parameter: NOx
Limit: 240 events (where one event is one startup and one shutdown) per twelve month period (event shall not exceed 1 hour)

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

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

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION
PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
Source Address: 8511 Welborn Road,, Mount Vernon47620, Indiana
Mailing Address: 20 Northwest Fourth Street, Evansville, IN 47741
Part 70 Permit No.: T129-26415-00010

Months: _____ to _ Year: _____

Page 1 of 2

This report shall be submitted quarterly based on a calendar year. Any deviation from the requirements, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".	
☐ NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.	
☐ THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

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

Form Completed by:_____

Title / Position: _____

Date:_____

Phone: _____

Attach a signed certification to complete this report.

Attachment A
to a Part 70 **Operating Permit** Renewal

40 CFR 60, Subpart D—Standards of Performance For Fossil-Fuel-Fired Steam Generators For Which Construction is Commenced After August 17, 1971

Source Name:	Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
Source Location:	8511 Welborn Road, Mt. Vernon, IN 47620
County:	Posey
SIC Code:	4911 and 3299
Significant Permit Modification No.:	129-26415-00010
Permit Reviewer:	Josiah Balogun
Emission unit	Unit No. 1

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971

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

§ 60.40 Applicability and designation of affected facility.

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

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

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

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

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

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

(e) Any facility covered under subpart Da is not covered under this subpart.

§ 60.41 Definitions.

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

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

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

Coal refuse means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

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

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

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

§ 60.42 Standard for particulate matter (PM).

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:

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

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

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

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

§ 60.43 Standard for sulfur dioxide (SO_2).

(a) Except as provided under paragraph (d) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2in excess of:

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

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

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

$$PS_{SO_2} = \frac{y\,(340) + z\,(520)}{(y + z)}$$

Where:

$PS_{SO}2$= Prorated standard for $S_{O2}$when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels or from all fossil fuels and wood residue fired;

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

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

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

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

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

§ 60.44 Standard for nitrogen oxides (NOX).

(a) Except as provided under paragraph (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NO_X, expressed as NO_2in excess of:

(1) 86 ng/J heat input (0.20 lb/MMBtu) derived from gaseous fossil fuel.

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

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

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

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

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

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

Where:

PS_{NOX}= Prorated standard for $NO_X$when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = Percentage of total heat input derived from lignite;

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

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

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

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

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

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

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous emissions monitoring systems (CEMS) for measuring the opacity of emissions, SO_2emissions, NO_Xemissions, and either oxygen (O_2) or carbon dioxide (CO_2) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil-fuel-fired steam generator that burns only gaseous fossil fuel and that does not use post-combustion technology to reduce emissions of SO_2or PM, CEMS for measuring the opacity of emissions and SO_2emissions are not required.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO_2emissions is not required if the owner or operator monitors SO_2emissions by fuel sampling and analysis.

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

(4) If an owner or operator does not install any CEMS for sulfur oxides and NO_X, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a CEMS for measuring either O_2or $CO_2$is not required.

(5) An owner or operator may petition the Administrator (in writing) to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.

(6) A CEMS for measuring the opacity of emissions is not required for a fossil fuel-fired steam generator that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

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

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

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

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

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

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

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

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

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

(1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of $SO_2$and NO_Xcontinuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in §60.46(d).

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

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

(i) Except as provided under paragraph (c)(3)(ii) of this section, $SO_2$and NO_Xspan values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO_2	Span value for NO_X
Gas	([1])	500.
Liquid	1,000	500.
Solid	1,500	1,000.
Combinations	1,000y + 1,500z	500 (x + y) + 1,000z.

[1]Not applicable.

Where:

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

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

z = Fraction of total heat input derived from solid fossil fuel.

(ii) As an alternative to meeting the requirements of paragraph (c)(3)(i) of this section, the owner or operator of an affected facility may elect to use the $SO_2$and NO_Xspan values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

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

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

(d) [Reserved]

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

(1) When a CEMS for measuring $O_2$is selected, the measurement of the pollutant concentration and O_2concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

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

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

(2) When a CEMS for measuring $CO_2$is selected, the measurement of the pollutant concentration and CO_2concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

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

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

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

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

(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^4 M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for $SO_2$and 46.01 for NO_X.

(3) $\%O_2$, $\%CO_2$= O_2or CO_2volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(4) F, F_c= a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and $F_c$are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = $2{,}723 \times 10^{-17}$dscm/J (10,140 dscf/MMBtu) and F_c= 0.532×10^{-17}scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = 2.637×10^{-7}dscm/J (9,820 dscf/MMBtu) and F_c= 0.486×10^{-7}scm CO_2/J (1,810 scf CO_2/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476×10^{-7}dscm/J (9,220 dscf/MMBtu) and F_c= 0.384×10^{-7}scm CO_2/J (1,430 scf CO_2/MMBtu).

(iv) For gaseous fossil fuels, F = 2.347×10^{-7}dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, F_c= 0.279×10^{-7}scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322×10^{-7}scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338×10^{-7}scm CO_2/J (1,260 scf CO_2/MMBtu) for butane.

(v) For bark F = 2.589×10^{-7}dscm/J (9,640 dscf/MMBtu) and F_c= 0.500×10^{-7}scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492×10^{-7}dscm/J (9,280 dscf/MMBtu) and F_c= 0.494×10^{-7}scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = 2.659×10^{-7}dscm/J (9,900 dscf/MMBtu) and F_c= 0.516×10^{-7}scm CO_2/J (1,920 scf CO_2/MMBtu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or $F_c$factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\,\frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5}(\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6}\,\frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

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

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

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

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

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

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

Where:

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

$F_i$or $(F_c)_i$= Applicable F or $F_c$factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and

n = Number of fuels being burned in combination.

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

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

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

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

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

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2as measured by a CEMS exceed the applicable standard under §60.43, or

(ii) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2as measured by a CEMS exceed the applicable standard under §60.43. Facilities complying with the 30-day SO_2standard shall use the most current associated SO_2compliance and monitoring requirements in §§60.48Da and 60.49Da of subpart Da of this part.

(3) *Nitrogen oxides* . Excess emissions for affected facilities using a CEMS for measuring $NO_X$are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under §60.44, or

(ii) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_Xas measured by a CEMS exceed the applicable standard under §60.43. Facilities complying with the 30-day NO_Xstandard shall use the most current associated NO_Xcompliance and monitoring requirements in §§60.48Da and 60.49Da of subpart Da of this part.

(4) *Particulate matter* . Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards under §60.43. Affected facilities using PM CEMS in lieu of a CEMS for monitoring opacity emissions must follow the most current applicable compliance and monitoring provisions in §§60.48Da and 60.49Da of subpart Da of this part.

§ 60.46 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, and subsequent performance tests as requested by the EPA Administrator, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (d) of this section.

(b) The owner or operator shall determine compliance with the PM, SO_2, and NO_Xstandards in §§60.42, 60.43, and 60.44 as follows:

(1) The emission rate (E) of PM, SO_2, or NO_Xshall be computed for each run using the following equation:

$$E = CF_d\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where:

E = Emission rate of pollutant, ng/J (1b/million Btu);

C = Concentration of pollutant, ng/dscm (1b/dscf);

$\%O_2$= O_2concentration, percent dry basis; and

F_d= Factor as determined from Method 19 of appendix A of this part.

(2) Method 5 of appendix A of this part shall be used to determine the PM concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B of appendix A of this part shall be used to determine the PM concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160±14 °C (320±25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration ($\%O_2$). The O_2sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2concentration for the run shall be the arithmetic mean of the sample O_2concentrations at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the O_2traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2traverse points.

(3) Method 9 of appendix A of this part and the procedures in §60.11 shall be used to determine opacity.

(4) Method 6 of appendix A of this part shall be used to determine the SO_2concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration ($\%O_2$). The O_2sample shall be taken simultaneously with, and at the same point as, the SO_2sample. The SO_2emission rate shall be computed for each pair of $SO_2$and O_2samples. The SO_2emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 of appendix A of this part shall be used to determine the NO_Xconcentration.

(i) The sampling site and location shall be the same as for the SO_2sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_Xsample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration ($\%O_2$). The sample shall be taken simultaneously with, and at the same point as, the NO_Xsample.

(iii) The NO_Xemission rate shall be computed for each pair of $NO_X$and O_2samples. The NO_Xemission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in §§60.43(b) and 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D2015, or D5865 (solid fuels), D240 (liquid fuels), or D1826 (gaseous fuels) (all of these methods are incorporated by reference, see §60.17) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Administrator.

(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in this section or in other sections as specified:

(1) The emission rate (E) of PM, $SO_2$and NO_Xmay be determined by using the Fc factor, provided that the following procedure is used:

(i) The emission rate (E) shall be computed using the following equation:

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

Where:

E = Emission rate of pollutant, ng/J (lb/MMBtu);

C = Concentration of pollutant, ng/dscm (lb/dscf);

$\%CO_2$= CO_2concentration, percent dry basis; and

F_c= Factor as determined in appropriate sections of Method 19 of appendix A of this part.

(ii) If and only if the average Fc factor in Method 19 of appendix A of this part is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B of appendix A of this part shall be used to determine the $O_2$and CO_2concentration according to the procedures in paragraph (b)(2)(ii), (4)(ii), or (5)(ii) of this section. Then if F_o(average of three runs), as calculated from the equation in Method 3B of appendix A of this part, is more than ±3 percent than the average $F_o$value, as determined from the average values of $F_d$and $F_c$in Method 19 of appendix A of this part, *i.e.* , F_{oa}= 0.209 (F_{da}/F_{ca}), then the following procedure shall be followed:

(A) When $F_o$is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, *e.g.* , if $F_o$is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When $F_o$is less than 0.97 $F_{oa}$and when the average difference (d) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, *e.g.* , if $F_o$is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When $F_o$is greater than 1.03 $F_{oa}$and when the average difference d is positive, then E shall be decreased by that proportion over 1.03 F_{oa}, *e.g.* , if $F_o$is 1.05 F_{oa}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B of appendix A of this part, Method 17 of appendix A of this part may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average

temperature of 16 0 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B of appendix A of this part may be used with Method 17 of appendix A of this part only if it is used after wet FGD systems. Method 17 of appendix A of this part shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO_2may be determined simultaneously with the Method 5 of appendix A of this part train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 of appendix A of this part is used in place of the condenser (section 2.1.7) of Method 5 of appendix A of this part.

(ii) All applicable procedures in Method 8 of appendix A of this part for the determination of SO_2(including moisture) are used:

(4) For Method 6 of appendix A of this part, Method 6C of appendix A of this part may be used. Method 6A of appendix A of this part may also be used whenever Methods 6 and 3B of appendix A of this part data are specified to determine the SO_2emission rate, under the conditions in paragraph (d)(1) of this section.

(5) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2concentration (%O_2) for the emission rate correction factor.

(6) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used.

(7) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

Browse Previous | Browse Next

Attachment B
to a Part 70 **Operating Permit** Renewal

40 CFR 60, Subpart Da—Standards of Performance for Electric Utility Steam Generating Units For Which Construction is Commenced After September 18, 1978

Source Name:	Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
Source Location:	8511 Welborn Road, Mt. Vernon, IN 47620
County:	Posey
SIC Code:	4911 and 3299
Significant Permit Modification No.:	129-26415-00010
Permit Reviewer:	Josiah Balogun
Emission unit	Unit No. 2

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

Source: 72 FR 32722, June 13, 2007, unless otherwise noted.

§ 60.40Da Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction, modification, or reconstruction is commenced after September 18, 1978.

(b) Combined cycle gas turbines (both the stationary combustion turbine and any associated duct burners) are subject to this part and not subject to subpart GG or KKKK of this part if:

(1) The combined cycle gas turbine is capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) The combined cycle gas turbine is designed and intended to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis; and

(3) The combined cycle gas turbine commenced construction, modification, or reconstruction after February 28, 2005.

(4) This subpart will continue to apply to all other electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the stationary combustion turbine is subject to either subpart GG or KKKK of this part, only emissions resulting from combustion of fuels in the steam-generating unit are

subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

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

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

§ 60.41Da Definitions.

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

Anthracite means coal that is classified as anthracite according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Available purchase power means the lesser of the following:

(a) The sum of available system capacity in all neighboring companies.

(b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.

(c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

Available system capacity means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

Biomass means plant materials and animal waste.

Bituminous coal means coal that is classified as bituminous according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Boiler operating day for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, *boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other fuels in any amount.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Cogeneration, also known as "combined heat and power," means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Combined cycle gas turbine means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

Dry flue gas desulfurization technology or *dry FGD* means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides (SO_2) from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry FGD technology include, but are not limited to, lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Electric utility combined cycle gas turbine means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

Electric utility company means the largest interconnected organization, business, or governmental entity that generates electric power for sale (*e.g.* , a holding company with operating subsidiary companies).

Electric utility steam-generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

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

Emergency condition means that period of time when:

(1) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(i) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(ii) All available purchase power interconnected with the affected facility is being obtained, or

(2) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(3) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under paragraph (1) of this definition apply.

Emission limitation means any emissions limit or operating limit.

Emission rate period means any calendar month included in a 12-month rolling average period.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the fuel burned in 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 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 (i.e., steam delivered to an industrial process).

24-hour period means the period of time between 12:01 a.m. and 12:00 midnight.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No coal is directly burned in the unit during operation.

Interconnected means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means coal that is classified as lignite A or B according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Natural gas means:

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

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per standard cubic meter (910 and 1,150 Btu per standard cubic foot).

Neighboring company means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Net system capacity means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas

desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Petroleum means crude oil or petroleum or a fuel derived from crude oil or petroleum, including, but not limited to, distillate oil, residual oil, and petroleum coke.

Potential combustion concentration means the theoretical emissions (nanograms per joule (ng/J), lb/MMBtu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems) and:

(1) For particulate matter (PM) is:

(i) 3,000 ng/J (7.0 lb/MMBtu) heat input for solid fuel; and

(ii) 73 ng/J (0.17 lb/MMBtu) heat input for liquid fuels.

(2) For sulfur dioxide (SO_2) is determined under §60.50Da(c).

(3) For nitrogen oxides (NO_X) is:

(i) 290 ng/J (0.67 lb/MMBtu) heat input for gaseous fuels;

(ii) 310 ng/J (0.72 lb/MMBtu) heat input for liquid fuels; and

(iii) 990 ng/J (2.30 lb/MMBtu) heat input for solid fuels.

Potential electrical output capacity means 33 percent of the maximum design heat input capacity of the steam generating unit, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr (*e.g.* , a steam generating unit with a 100 MW (340 MMBtu/hr) fossil-fuel heat input capacity would have a 289,080 MWh 12 month potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

Principal company means the electric utility company or companies which own the affected facility.

Resource recovery unit means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

Responsible official means responsible official as defined in 40 CFR 70.2.

Solid-derived fuel means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, synthetic gas, gasified coal, gasified petroleum coke, gasified biomass, and gasified tire derived fuel.

Spare flue gas desulfurization system module means a separate system of SO_2emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

Spinning reserve means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power distribution system and that are capable of immediately accepting additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

System emergency reserves means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

System load means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (*e.g.* , emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

Wet flue gas desulfurization technology or *wet FGD* means a SO_2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet FGD technology include, but are not limited to, lime, limestone, and sodium.

§ 60.42Da Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain PM in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the initial PM performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(c) Except as provided in paragraph (d) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or

required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain PM in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel.

§ 60.43Da Standard for sulfur dioxide (SO2).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain SO_2in excess of:

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain SO_2in excess of:

(1) 340 ng/J (0.80 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC–I) any gases that contain SO_2in excess of 520 ng/J (1.20 lb/MMBtu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/MMBtu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite;

(2) Is classified as a resource recovery unit; or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/MMBtu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO_2commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of $SO_2$to the atmosphere are greater than 260 ng/J (0.60 lb/MMBtu) heat input

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = 10$$

(2) If emissions of $SO_2$to the atmosphere are equal to or less than 260 ng/J (0.60 lb/MMBtu) heat input:

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = \frac{(10x + 30y)}{100}$$

Where:

E_s= Prorated SO_2emission limit (ng/J heat input);

$\%P_s$= Percentage of potential SO_2emission allowed;

x = Percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels); and

y = Percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels).

(i) Except as provided in paragraphs (j) and (k) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(j) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, shall caused to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area that commenced construction, reconstruction, or modification commenced after February 28, 2005, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input on a 30-day rolling average basis.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of if the affected facility or 230 ng/J (0.54 lb/MMBtu) heat input on a 30-day rolling average basis.

§ 60.44Da Standard for nitrogen oxides (NOX).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b), (d), (e), and (f) of this section, any gases that contain NO_X(expressed as NO_2) in excess of the following emission limits, based on a 30-day rolling average basis, except as provided under §60.48Da(j)(1):

(1) NO_Xemission limits.

Fuel type	Emission limit for heat input	
	ng/J	lb/MMBtu
Gaseous fuels:		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
Liquid fuels:		
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse	(1)	(1)
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace[2]	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit[2]	260	0.60
Subbituminous coal	210	0.50
Bituminous coal	260	0.60
Anthracite coal	260	0.60
All other fuels	260	0.60

[1]Exempt from NO_Xstandards and NO_Xmonitoring requirements.

[2]Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) NO_Xreduction requirement.

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25
Liquid fuels	30
Solid fuels	65

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(c) Except as provided under paragraphs (d), (e), and (f) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$E_n = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

Where:

E_n= Applicable standard for $NO_X$when multiple fuels are combusted simultaneously (ng/J heat input);

w = Percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x = Percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y = Percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z = Percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v = Percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(d)(1) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction after July 9, 1997, but before or on February 28, 2005 shall cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, based on a 30-day rolling average basis, except as provided under §60.48Da(k).

(2) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of affected facility for which reconstruction commenced after July 9,

1997, but before or on February 28, 2005 shall cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 65 ng/J (0.15 lb/MMBtu) heat input, based on a 30-day rolling average basis.

(e) Except for an IGCC electric utility steam generating unit meeting the requirements of paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X(expressed as NO_2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under §60.48Da(k).

(2) For an affected facility for which reconstruction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis.

(f) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output on a 30-day rolling average basis.

(3) In cases when during a 30-day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

§ 60.45Da Standard for mercury (Hg).

(a) For each coal-fired electric utility steam generating unit other than an IGCC electric utility steam generating unit, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases that contain mercury (Hg) emissions in excess of each Hg emissions

limit in paragraphs (a)(1) through (5) of this section that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average basis using the procedures in §60.50Da(h).

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 20×10^{-6} pound per megawatt hour (lb/MWh) or 0.020 lb/gigawatt-hour (GWh) on an output basis. The International System of Units (SI) equivalent is 0.0025 ng/J.

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal:

(i) If your unit is located in a county-level geographical area receiving greater than 25 inches per year (in/yr) mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 66×10^{-6} lb/MWh or 0.066 lb/GWh on an output basis. The SI equivalent is 0.0083 ng/J.

(ii) If your unit is located in a county-level geographical area receiving less than or equal to 25 in/yr mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 97×10^{-6} lb/MWh or 0.097 lb/GWh on an output basis. The SI equivalent is 0.0122 ng/J.

(3) For each coal-fired electric utility steam generating unit that burns only lignite, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 175×10^{-6} lb/MWh or 0.175 lb/GWh on an output basis. The SI equivalent is 0.0221 ng/J.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 16×10^{-6} lb/MWh or 0.016 lb/GWh on an output basis. The SI equivalent is 0.0020 ng/J.

(5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks (*i.e.* , bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the unit-specific Hg emissions limit established according to paragraph (a)(5)(i) or (ii) of this section, as applicable to the affected unit.

(i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the Btu, MWh, or MJ) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 in this section. For each affected source, you must comply with the weighted Hg emissions limit calculated using Equation 1 in this section based on the total Hg emissions from the unit and the total Btu, MWh, or MJ contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^{n} EL_i (HH_i)}{\sum_{i=1}^{n} HH_i} \qquad \text{(Eq. 1)}$$

Where:

EL_b= Total allowable Hg in lb/MWh that can be emitted to the atmosphere from any affected source being averaged according to this paragraph.

EL_i= Hg emissions limit for the subcategory i (coal rank) that applies to affected source, lb/MWh;

HH_i= For each affected source, the Btu, MWh, or MJ contributed by the corresponding subcategory i (coal rank) burned during the compliance period; and

n = Number of subcategories (coal ranks) being averaged for an affected source.

(ii) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse together with one or more non-regulated, supplementary fuels, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emission limit based on the Btu, MWh, or MJ contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 in this section. For each affected source. You must comply with the weighted Hg emissions limit calculated using Equation 1 in this section based on the total Hg emissions from the unit contributed by both regulated and nonregulated fuels burned during the compliance period and the total Btu, MWh, or MJ contributed by both regulated and nonregulated fuels burned during the compliance period.

(b) For each IGCC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases that contain Hg emissions in excess of 20×10^{-6} lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average basis using the procedures in §60.50Da(h).

§ 60.46Da [Reserved]

§ 60.47Da Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC–I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2emission reduction requirements under §60.43Da(c) but must, as a minimum, reduce SO_2emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2emission reduction requirements under §60.43Da(a) but must, as a minimum, reduce SO_2emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NO_Xemission limitation and percent reduction under §60.44Da(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/MMBtu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SCR I)	SO2	6,000–10,000
Fluidized bed combustion (atmospheric)	SO2	400–3,000

Fluidized bed combustion (pressurized)	SO2	400–1,200
Coal liquification	NOX	750–10,000
Total allowable for all technologies		15,000

§ 60.48Da Compliance provisions.

(a) Compliance with the PM emission limitation under §60.42Da(a)(1) constitutes compliance with the percent reduction requirements for PM under §60.42Da(a)(2) and (3).

(b) Compliance with the NO_Xemission limitation under §60.44Da(a)(1) constitutes compliance with the percent reduction requirements under §60.44Da(a)(2).

(c) The PM emission standards under §60.42Da, the NO_Xemission standards under §60.44Da, and the Hg emission standards under §60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if SO_2emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any SO_2emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 MMBtu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph under §60.43Da(a), (b), (d), (e), and (h) for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

(e) After the initial performance test required under §60.8, compliance with the SO_2emission limitations and percentage reduction requirements under §60.43Da and the NO_Xemission limitations under §60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both $SO_2$and $NO_X$and a new percent reduction for $SO_2$are calculated to show compliance with the standards.

(f) For the initial performance test required under §60.8, compliance with the SO_2emission limitations and percent reduction requirements under §60.43Da and the NO_Xemission limitation under §60.44Da is based on the average emission rates for SO_2, NO_X, and percent reduction for $SO_2$for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30

successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

(1) Compliance with applicable 30-day rolling average $SO_2$and NO_Xemission limitations is determined by calculating the arithmetic average of all hourly emission rates for $SO_2$and $NO_X$for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_Xonly), or emergency conditions (SO_2only).

(2) Compliance with applicable SO_2percentage reduction requirements is determined based on the average inlet and outlet SO_2emission rates for the 30 successive boiler operating days.

(3) Compliance with applicable daily average PM emission limitations is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. Averages are only calculated for boiler operating days that have valid data for at least 18 hours of unit operation during which the standard applies. Instead, the valid hourly emission rates are averaged with the next boiler operating day with 18 hours or more of valid PM CEMS data to determine compliance.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under §60.49Da of this subpart, compliance of the affected facility with the emission requirements under §§60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19 of appendix A of this part.

(i) *Compliance provisions for sources subject to §60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), or (f)* . The owner or operator of an affected facility subject to §60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), or (f) shall calculate NO_Xemissions as 1.194×10^{-7} lb/scf-ppm times the average hourly NO_Xoutput concentration in ppm (measured according to the provisions of §60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)). Alternatively, for oil-fired and gas-fired units, NO_Xemissions may be calculated by multiplying the hourly NO_Xemission rate in lb/MMBtu (measured by the CEMS required under §§60.49Da(c) and (d)), by the hourly heat input rate (measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)).

(j) *Compliance provisions for duct burners subject to §60.44Da(a)(1)* . To determine compliance with the emissions limits for NO_Xrequired by §60.44Da(a) for duct burners used in combined cycle systems, either of the procedures described in paragraph (j)(1) or (2) of this section may be used:

(1) The owner or operator of an affected duct burner shall conduct the performance test required under §60.8 using the appropriate methods in appendix A of this part. Compliance with the emissions limits under §60.44Da(a)(1) is determined on the average of three (nominal 1-hour) runs for the initial and subsequent performance tests. During the performance test, one sampling site shall be located in the exhaust of the turbine prior to the duct burner. A second sampling site shall be located at the outlet from the heat recovery steam generating unit. Measurements shall be taken at both sampling sites during the performance test; or

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the continuous emission monitoring system (CEMS) specified under §60.49Da for measuring $NO_X$and oxygen (O_2) (or carbon dioxide (CO_2)) and meet the requirements of §60.49Da. Alternatively, data from a NO_Xemission rate (*i.e.* , NO_X-diluent) CEMS certified according to the provisions of §75.20(c) of this chapter and appendix A to part 75 of this chapter, and meeting the quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used, with the following caveats. Data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit. The NO_Xemission rate at the outlet from the steam generating unit shall constitute the NO_Xemission rate from the duct burner of the combined cycle system.

(k) *Compliance provisions for duct burners subject to §60.44Da(d)(1) or (e)(1)* . To determine compliance with the emission limitation for NO_Xrequired by §60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NO_Xemission limitation in §60.44Da(d)(1) or (e)(1) as follows:

(i) The emission rate (E) of NO_Xshall be computed using Equation 2 in this section:

$$E = \frac{(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})}{(O_{sg} \times h)} \qquad \text{(Eq. 2)}$$

Where:

E = Emission rate of $NO_X$from the duct burner, ng/J (lb/MWh) gross output;

C_{sg}= Average hourly concentration of NO_Xexiting the steam generating unit, ng/dscm (lb/dscf);

C_{te}= Average hourly concentration of NO_Xin the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);

Q_{sg}= Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr);

Q_{te}= Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr);

O_{sg}= Average hourly gross energy output from steam generating unit, J (MWh); and

h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(ii) Method 7E of appendix A of this part shall be used to determine the NO_Xconcentrations ($C_{sg}$and C_{te}). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates ($Q_{sg}$and Q_{te}) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable NO_Xemission limitation in §60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable NO_Xemission limitation in §60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of NO_Xshall be computed using Equation 3 in this section:

$$E = \frac{(C_{sg} \times Q_{sd})}{O_{sg}} \qquad \text{(Eq. 3)}$$

Where:

E = Emission rate of $NO_X$from the duct burner, ng/J (lb/MWh) gross output;

C_{sg}= Average hourly concentration of NO_Xexiting the steam generating unit, ng/dscm (lb/dscf);

Q_{sg}= Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr); and

O_{cc}= Average hourly gross energy output from entire combined cycle unit, J (MWh).

(ii) The CEMS specified under §60.49Da for measuring $NO_X$and O_2(or CO_2) shall be used to determine the average hourly NO_Xconcentrations (C_{sg}). The continuous flow monitoring system specified in §60.49Da(l) or §60.49Da(m) shall be used to determine the volumetric flow rate (Q_{sg}) of the exhaust gas. If the option to use the flow monitoring system in §60.49Da(m) is selected, the flow rate data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit.

(iii) The continuous monitoring system specified under §60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit (O_{cc}), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in §60.49Da(l), determine the mass rate (lb/hr) of NO_Xemissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of NO_Xshall be computed using Equation 4 in this section:

$$E = \frac{\left(ER_{sg} \times H_{cc}\right)}{O_{cc}} \qquad \text{(Eq. 4)}$$

Where:

E = Emission rate of $NO_X$from the duct burner, ng/J (lb/MWh) gross output;

ER_{sg}= Average hourly emission rate of NO_Xexiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu);

H_{cc}= Average hourly heat input rate of entire combined cycle unit, J/hr (MMBtu/hr); and

O_{cc}= Average hourly gross energy output from entire combined cycle unit, J (MWh).

(3) When an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

(i) Determine compliance with the applicable NO_Xemissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common steam turbine; or

(ii) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(l) *Compliance provisions for sources subject to §60.45Da.* The owner or operator of an affected facility subject to §60.45Da (new sources constructed or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of §60.49Da(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of §60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in §60.49Da(k). Compliance with the applicable standard under §60.45Da is determined on a 12-month rolling average basis.

(m) *Compliance provisions for sources subject to §60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), or (j)(3)(i).* The owner or operator of an affected facility subject to §60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), or (j)(3)(i) shall calculate SO_2emissions as 1.660×10^{-7}lb/scf-ppm times the average hourly SO_2output concentration in ppm (measured according to the provisions of §60.49Da(b)), times the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)). Alternatively, for oil-fired and gas-fired units, SO_2emissions may be calculated by multiplying the hourly SO_2emission rate (in lb/MMBtu), measured by the CEMS required under §60.49Da, by the hourly heat input rate (measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)).

(n) *Compliance provisions for sources subject to §60.42Da(c)(1).* The owner or operator of an affected facility subject to §60.42Da(c)(1) shall calculate PM emissions by multiplying the average hourly PM output concentration, measured according to the provisions of §60.49Da(t), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of §60.49Da(k). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) *Compliance provisions for sources subject to §60.42Da(c)(2) or (d).* Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section and use a COMS to demonstrate compliance with §60.42Da(b).

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in 60.42Da(c)(2) or (d) by the applicable date specified in §60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months of the date of the prior performance test. You must conduct each performance test according to the requirements in §60.8 using the test methods and procedures in §60.50Da.

(2) You must monitor the performance of each electrostatic precipitator or fabric filter (baghouse) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) using a continuous opacity monitoring system (COMS) according to the requirements in paragraphs (o)(2)(i) through (vi) unless you elect to comply with one of the alternatives provided in paragraphs (o)(3) and (o)(4) of this section, as applicable to your control device.

(i) Each COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B.

(ii) You must comply with the quality assurance requirements in paragraphs (o)(4)(ii)(A) through (E) of this section.

(A) You must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in 40 CFR part 60, appendix B.

(B) You must adjust the zero and span whenever the 24-hour zero drift or 24-hour span drift exceeds 4 percent opacity. The COMS must allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified. The optical surfaces exposed to the effluent gases must be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments. For systems using automatic zero adjustments, the optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(C) You must apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light

beam. All procedures applied must provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(D) Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS must be in continuous operation and must complete a minimum of one cycle of sampling and analyzing for each successive 10 second period and one cycle of data recording for each successive 6-minute period.

(E) You must reduce all data from the COMS to 6-minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments must not be included in the data averages. An arithmetic or integrated average of all data may be used.

(iii) During each performance test conducted according to paragraph (o)(1) of this section, you must establish an opacity baseline level. The value of the opacity baseline level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurements recorded during each of the test run intervals conducted for the performance test, and then adding 2.5 percent opacity to your calculated average opacity value for all of the test runs. If your calculated average opacity value for all of the test runs is less than 5.0 percent, then the opacity baseline level is set at 5.0 percent.

(iv) You must evaluate the preceding 24-hour average opacity level measured by the COMS each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the measured 24-hour average opacity emission level is greater than the baseline opacity level determined in paragraph (o)(2)(iii) of this section, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high opacity incident and take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the measured 24-hour average opacity to a level below the baseline opacity level.

(v) You must record the opacity measurements, calculations performed, and any corrective actions taken. The record of corrective action taken must include the date and time during which the measured 24-hour average opacity was greater than baseline opacity level, and the date, time, and description of the corrective action.

(vi) If the measured 24-hour average opacity for your affected source remains at a level greater than the opacity baseline level after 7 days, then you must conduct a new PM performance test according to paragraph (o)(1) of this section and establish a new opacity baseline value according to paragraph (o)(2) of this section. This new performance test must be conducted within 60 days of the date that the measured 24-hour average opacity was first determined to exceed the baseline opacity level unless a wavier is granted by the appropriate delegated permitting authority.

(3) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of an electrostatic precipitator (ESP) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) using an ESP predictive model developed in accordance with the requirements in paragraphs (o)(3)(i) through (v) of this section.

(i) You must calibrate the ESP predictive model with each PM control device used to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) operating under normal conditions. In cases when a wet scrubber is used in combination with an ESP to comply with the PM emissions limit, the daily average liquid-to-gas flow rate for the wet scrubber must be maintained at 90 percent of average ratio measured during all test run intervals for the performance test conducted according to paragraph (o)(1) of this section.

(ii) You must develop a site-specific monitoring plan that includes a description of the ESP predictive model used, the model input parameters, and the procedures and criteria for establishing monitoring parameter baseline levels indicative of compliance with the PM emissions limit. You must submit the site-specific monitoring plan for approval by the appropriate delegated permitting authority. For reference purposes in preparing the monitoring plan, see the OAQPS “Compliance Assurance Monitoring (CAM) Protocol for an Electrostatic Precipitator (ESP) Controlling Particulate Matter (PM) Emissions from a Coal-Fired Boiler.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality Planning and Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Continuous Emission Monitoring .

(iii) You must run the ESP predictive model using the applicable input data each boiler operating day and evaluate the model output for the preceding boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the values for one or more of the model parameters exceed the applicable baseline levels determined according to your approved site-specific monitoring plan, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of a model parameter deviation and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to return the model output to within the applicable baseline levels.

(iv) You must record the ESP predictive model inputs and outputs and any corrective actions taken. The record of corrective action taken must include the date and time during which the model output values exceeded the applicable baseline levels, and the date, time, and description of the corrective action.

(v) If after 7 consecutive days a model parameter continues to exceed the applicable baseline level, then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 days of the date that the model parameter was first determined to exceed its baseline level unless a wavier is granted by the appropriate delegated permitting authority.

(4) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of a fabric filter (baghouse) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) by using a bag leak detection system according to the requirements in paragraphs (o)(4)(i) through (v) of this section.

(i) Each bag leak detection system must meet the specifications and requirements in paragraphs (o)(4)(i)(A) through (H) of this section.

(A) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic foot) or less.

(B) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator must continuously record the output from the bag leak detection system using electronic or other means (*e.g.* , using a strip chart recorder or a data logger.)

(C) The bag leak detection system must be equipped with an alarm system that will react when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (o)(4)(i)(D) of this section, and the alarm must be located such that it can be noticed by the appropriate plant personnel.

(D) In the initial adjustment of the bag leak detection system, you must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(E) Following initial adjustment, you must not adjust the averaging period, alarm set point, or alarm delay time without approval from the appropriate delegated permitting authority except as provided in paragraph (d)(1)(vi) of this section.

(F) Once per quarter, you may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (o)(4)(ii) of this section.

(G) You must install the bag leak detection sensor downstream of the fabric filter and upstream of any wet scrubber.

(H) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(ii) You must develop and submit to the appropriate delegated permitting authority for approval a site-specific monitoring plan for each bag leak detection system. You must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (o)(4)(ii)(A) through (F) of this section.

(A) Installation of the bag leak detection system;

(B) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(C) Operation of the bag leak detection system, including quality assurance procedures;

(D) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(E) How the bag leak detection system output will be recorded and stored; and

(F) Corrective action procedures as specified in paragraph (o)(4)(iii) of this section. In approving the site-specific monitoring plan, the appropriate delegated permitting authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

(iii) For each bag leak detection system, you must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (o)(4)(ii)(F) of this section, you must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

(A) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(B) Sealing off defective bags or filter media;

(C) Replacing defective bags or filter media or otherwise repairing the control device;

(D) Sealing off a defective fabric filter compartment;

(E) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(F) Shutting down the process producing the particulate emissions.

(iv) You must maintain records of the information specified in paragraphs (o)(4)(iv)(A) through (C) of this section for each bag leak detection system.

(A) Records of the bag leak detection system output;

(B) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(C) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 3 hours of the alarm.

(v) If after any period of composed of 30 boiler operating days during which the alarm rate exceeds 5 percent of the process operating time (excluding control device or process startup, shutdown, and malfunction), then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 days of the date that the alarm rate was first determined to exceed 5 percent limit unless a wavier is granted by the appropriate delegated permitting authority.

(5) An owner or operator of a modified affected source electing to meet the emission limitations in §.42Da(d) shall determine the percent reduction in PM by using the emission rate for PM determined by the performance test

conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, certify, maintain, and operate a CEMS measuring PM emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a CEMS measuring PM. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in §60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19 of appendix A of this part, section 4.1.

(5) At a minimum, valid CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-day rolling average basis. Beginning on January 1, 2012, valid CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average basis.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/hr, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(7) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30-day rolling average.

§ 60.49Da Emission monitoring.

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO_2control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2control device.

(2) For a facility that qualifies under the numerical limit provisions of §60.43Da(d), (i), (j), or (k) SO_2emissions are only monitored as discharged to the atmosphere.

(3) An “as fired” fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of appendix A of this part may be used to determine potential SO_2emissions in place of a continuous SO_2emission monitor at the inlet to the SO_2control device as required under paragraph (b)(1) of this section.

(4) If the owner or operator has installed and certified a SO_2continuous emissions monitoring system (CEMS) according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used to meet the requirements of this section, provided that:

(i) A CO_2or O_2continuous monitoring system is installed, calibrated, maintained and operated at the same location, according to paragraph (d) of this section; and

(ii) For sources subject to an SO_2emission limit in lb/MMBtu under §60.43Da:

(A) When relative accuracy testing is conducted, SO_2concentration data and CO_2(or O_2) data are collected simultaneously; and

(B) In addition to meeting the applicable $SO_2$and CO_2(or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(iii) The reporting requirements of §60.51Da are met. The $SO_2$and CO_2(or O_2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2data have been bias adjusted according to the procedures of part 75 of this chapter.

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_Xemissions discharged to the atmosphere; or

(2) If the owner or operator has installed a NO_Xemission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.51Da. Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2or carbon dioxide (CO_2) content of the flue gases at each location where SO_2or NO_Xemissions are monitored. For affected facilities subject to a lb/MMBtu SO_2emission limit under §60.43Da, if the owner or operator has installed and certified a CO_2or O_2monitoring system according to §75.20(c) of this chapter and Appendix A to part 75 of this chapter and the monitoring system continues to meet the applicable quality-assurance provisions of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used together with the part 75 SO_2concentration monitoring system described in paragraph (b) of this section, to determine the SO_2emission rate in lb/MMBtu. SO_2data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

(f)(1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph §60.13(h) are expressed in ng/J (lb/MMBtu) heat input and used to calculate the average emission rates under §60.48Da. The 1-hour averages are calculated using the data points required under §60.13(h)(2).

(h) When it becomes necessary to supplement CEMS data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 of appendix A of this part shall be used to determine the SO_2concentration at the same location as the SO_2monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 of appendix A of this part shall be used to determine the NO_Xconcentration at the same location as the NO_Xmonitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2or CO_2concentration at the same location as the O_2or CO_2monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 of appendix A of this part shall be used to compute each 1-hour average concentration in ng/J (lb/MMBtu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under §60.13(c) and calibration checks under §60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7 of appendix A of this part shall be used to determine O_2, SO_2, and NO_Xconcentrations, respectively.

(2) SO_2or NO_X(NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a CEMS for measuring opacity is between 60 and 80 percent. Span values for a CEMS measuring NO_Xshall be determined using one of the following procedures:

(i) Except as provided under paragraph (i)(3)(ii) of this section, NO_Xspan values shall be determined as follows:

Fossil fuel	**Span values for NO_X (ppm)**
Gas	500.

Liquid	500.
Solid	1,000.
Combination	500 (x + y) + 1,000z.

Where:

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

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

z = Fraction of total heat input derived from solid fossil fuel.

(ii) As an alternative to meeting the requirements of paragraph (i)(3)(i) of this section, the owner or operator of an affected facility may elect to use the NO_Xspan values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (i)(3)(i) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (i)(3)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel and determining span values under paragraph (i)(3)(i) of this section, the span value of the SO_2CEMS at the inlet to the SO_2control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the SO_2control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired. For affected facilities determining span values under paragraph (i)(3)(ii) of this section, SO_2span values shall be determined according to section 2.1.1 in appendix A to part 75 of this chapter.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 6 of appendix A of this part, Method 6A or 6B (whenever Methods 6 and 3 or 3B of appendix A of this part data are used) or 6C of appendix A of this part may be used. Each Method 6B of appendix A of this part sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B of appendix A of this part is used under paragraph (i) of this section, the conditions under §60.48Da(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be 1 hour.

(3) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used if the sampling time is 1 hour.

(4) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under §60.44Da(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in MWh on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under §60.42Da, §60.43Da, §60.44Da, or §60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the CD assessment, RATA and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of §75.20(c) of this chapter and appendix A to part 75 of this chapter, and continuing to meet the applicable quality control and quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used. Flow rate data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of part 75 of this chapter.

(o) The owner or operator of a duct burner, as described in §60.41Da, which is subject to the NO_Xstandards of §60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a CEMS to measure NO_Xemissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in §60.45Da shall install and operate a CEMS to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to §75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of each CEMS according to the requirements of §60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in §60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in §60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (i.e., valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in §72.2 of this chapter) to monitor Hg concentration, according to the procedures described in §75.15 of this chapter and appendix K to part 75 of this chapter.

(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of §75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in §75.11(b) or §75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (*e.g.* , on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of §60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of §60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing recordkeeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under §60.42Da(c)(1) shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected source demonstrating compliance with the input-based emission limitation under §60.42Da(c)(2) may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) An owner or operator of an affected source that meets the conditions in either paragraph (u)(1), (2) or (3) of this section is exempted from the continuous opacity monitoring system requirements in paragraph (a) of this section and the monitoring requirements in §60.48Da(o).

(1) A CEMS for measuring PM emissions is used to demonstrate continuous compliance on a boiler operating day average with the emissions limitations under §60.42Da(a)(1) or §60.42Da(c)(2) and is installed, certified, operated, and maintained on the affected source according to the requirements of paragraph (v) of this section; or

(2) The affected source burns only gaseous fuels and does not use a post-combustion technology to reduce emissions of SO_2or PM; or

(3) The affected source does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (u)(3)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (u)(3)(i)(A) through (D) of this section.

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

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

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

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

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

(iii) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 1.4 lb/MWh, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 1.4 lb/MWh or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (u)(3) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which

the 24-hour average CO emission level was greater than 1.4 lb/MWh, and the date, time, and description of the corrective action.

(v) The owner or operator of an affected facility using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (v)(1) through (v)(3).

(1) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of §60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each relative accuracy test run of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2(or CO_2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using the following test methods.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For O_2(or CO_2), EPA Reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(w)(1) Except as provided for under paragraphs (w)(2), (w)(3), and (w)(4) of this section, the SO_2, NO_X, CO_2, and O_2CEMS required under paragraphs (b) through (d) of this section shall be installed, certified, and operated in accordance with the applicable procedures in Performance Specification 2 or 3 in appendix B to this part or according to the procedures in appendices A and B to part 75 of this chapter. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in appendix F to this part, and a data assessment report (DAR), prepared according to section 7 of Procedure 1 in appendix F to this part, shall be submitted with each compliance report required under §60.51Da., the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(2) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For all required $CO_2$and O_2CEMS and for $SO_2$and NO_XCEMS with span values greater than 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F of this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to $SO_2$and NO_Xspan values less than 100 ppm;

(3) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For all required $CO_2$and O_2CEMS and for $SO_2$and NO_XCEMS with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for $SO_2$and NO_Xspan values less than or equal to 30 ppm;

(4) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For SO_2, CO_2, and O_2CEMS and for NO_XCEMS, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of

this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2(regardless of the SO_2emission level during the RATA), and for $NO_X$when the average NO_Xemission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu;

(5) If the owner or operator elects to implement the alternative data assessment procedures described in paragraphs (w)(2) through (w)(4) of this section, each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by paragraphs (w)(2) through (w)(4) of this section.

§ 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for $SO_2$and NO_X. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the PM standards in §60.42Da as follows:

(1) The dry basis F factor (O_2) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(2) For the particular matter concentration, Method 5 of appendix A of this part shall be used at affected facilities without wet FGD systems and Method 5B of appendix A of this part shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160±14 °C (320±25 °F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the O_2concentration. The O_2sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2traverse points. If the grab sampling procedure is used, the O_2concentration for the run shall be the arithmetic mean of the sample O_2concentrations at all traverse points.

(3) Method 9 of appendix A of this part and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO_2standards in §60.43Da as follows:

(1) The percent of potential SO_2emissions (%Ps) to the atmosphere shall be computed using the following equation:

$$\%P_s = \frac{(100 - \%R_f)(100 - \%R_g)}{100}$$

Where:

%Ps = Percent of potential SO_2emissions, percent;

%Rf = Percent reduction from fuel pretreatment, percent; and

%Rg = Percent reduction by SO_2control system, percent.

(2) The procedures in Method 19 of appendix A of this part may be used to determine percent reduction ($\%R_f$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and fly ash interactions. This determination is optional.

(3) The procedures in Method 19 of appendix A of this part shall be used to determine the percent SO_2reduction ($\%R_g$) of any SO_2control system. Alternatively, a combination of an “as fired” fuel monitor and emission rates measured after the control system, following the procedures in Method 19 of appendix A of this part, may be used if the percent reduction is calculated using the average emission rate from the SO_2control device and the average SO_2input rate from the “as fired” fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate.

(5) The CEMS in §60.49Da(b) and (d) shall be used to determine the concentrations of $SO_2$and CO_2or O_2.

(d) The owner or operator shall determine compliance with the NO_Xstandard in §60.44Da as follows:

(1) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate of NO_X.

(2) The continuous monitoring system in §60.49Da(c) and (d) shall be used to determine the concentrations of $NO_X$and CO_2or O_2.

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 5 or 5B of appendix A of this part, Method 17 of appendix A of this part may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of §§2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after wet FGD systems. Method 17 of appendix A of this part shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The $F_c$factor (CO_2) procedures in Method 19 of appendix A of this part may be used to compute the emission rate of PM under the stipulations of §60.46(d)(1). The CO_2shall be determined in the same manner as the O_2concentration.

(f) Electric utility combined cycle gas turbines are performance tested for PM, SO_2, and NO_Xusing the procedures of Method 19 of appendix A of this part. The $SO_2$and NO_Xemission rates from the gas turbine used in Method 19 of appendix A of this part calculations are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

(g) For the purposes of determining compliance with the emission limits in §60.45Da, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus 75 percent of the equivalent electrical energy (measured relative to ISO conditions) in the unit's process stream.

(1) All conversions from Btu/hr unit input to MW unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (*i.e.* , 250 MMBtu/hr input to an electric utility steam generating unit is equivalent to 73 MW input to the electric utility steam generating unit); 73 MW input to the electric utility steam generating unit is equivalent to 25 MW output from the boiler electric utility steam generating unit; therefore, 250 MMBtu input to the electric utility steam generating unit is equivalent to 25 MW output from the electric utility steam generating unit).

(2) Use the Equation 5 in this section to determine the cogeneration Hg emission rate over a specific compliance period.

$$ER_{cogen} = \frac{M}{\left(V_{grid} + 0.75 \times V_{process}\right)} \qquad \text{(Eq. 5)}$$

Where:

ER_{cogen}= Cogeneration Hg emission rate over a compliance period in lb/MWh;

E = Mass of Hg emitted from the stack over the same compliance period (lb);

V_{grid}= Amount of energy sent to the grid over the same compliance period (MWh); and

$V_{process}$= Amount of energy converted to steam for process use over the same compliance period (MWh).

(h) The owner or operator shall determine compliance with the Hg limit in §60.45Da according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The initial performance test shall be commenced by the applicable date specified in §60.8(a). The required CEMS must be certified prior to commencing the test. The performance test consists of collecting hourly Hg emission data (lb/MWh) with the CEMS for 12 successive months of unit operation (excluding hours of unit startup, shutdown and malfunction). The average Hg emission rate is calculated for each month, and then the weighted, 12-month average Hg emission rate is calculated according to paragraph (h)(2) or (h)(3) of this section, as applicable. If, for any month in the initial performance test, the minimum data capture requirement in §60.49Da(p)(4)(i) is not met, the owner or operator shall report a substitute Hg emission rate for that month, as follows. For the first such month, the substitute monthly Hg emission rate shall be the arithmetic average of all valid hourly Hg emission rates recorded to date. For any subsequent month(s) with insufficient data capture, the substitute monthly Hg emission rate shall be the highest valid hourly Hg emission rate recorded to date. When the 12-month average Hg emission rate for the initial performance test is calculated, for each month in which there was insufficient data capture, the substitute monthly Hg emission rate shall be weighted according to the number of unit operating hours in that month. Following the initial performance test, the owner or operator shall demonstrate compliance by calculating the weighted average of all monthly Hg emission rates (in lb/MWh) for each 12 successive calendar months, excluding data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (iii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in lb, using either Equation 6 in paragraph (h)(2)(i)(A) of this section or Equation 7 in paragraph (h)(2)(i)(B) of this section, in conjunction with Equation 8 in paragraph (h)(2)(i)(C) of this section.

(A) If the Hg CEMS measures Hg concentration on a wet basis, use Equation 6 below to calculate the Hg mass emissions for each valid hour:

$$E_h = KC_h Q_h t_h \qquad \text{(Eq. 6)}$$

Where:

E_h= Hg mass emissions for the hour, (lb);

K = Units conversion constant, 6.24×10^{-11} lb-scm/μgm-scf;

C_h= Hourly $H_g$concentration, wet basis, (µgm/scm);

Q_h= Hourly stack gas volumetric flow rate, (scfh); and

t_h= Unit operating time, i.e., the fraction of the hour for which the unit operated. For example, th = 0.50 for a half-hour of unit operation and 1.00 for a full hour of operation.

(B) If the Hg CEMS measures Hg concentration on a dry basis, use Equation 7 below to calculate the Hg mass emissions for each valid hour:

$$E_h = KC_h Q_h t_h (1 - B_{ws}) \qquad \text{(Eq. 7)}$$

Where:

E_h= Hg mass emissions for the hour, (lb);

K = Units conversion constant, 6.24×10^{-11}lb-scm/µgm-scf;

C_h= Hourly Hg concentration, dry basis, (µgm/dscm);

Q_h= Hourly stack gas volumetric flow rate, (scfh);

t_h= Unit operating time, *i.e.* , the fraction of the hour for which the unit operated; and

B_{ws}= Stack gas moisture content, expressed as a decimal fraction (*e.g.* , for 8 percent H_2O, B_{ws}= 0.08).

(C) Use Equation 8, below, to calculate M, the total mass of Hg emitted for the month, by summing the hourly masses derived from Equation 6 or 7 (as applicable):

$$M = \sum_{h=1}^{n} E_h \qquad \text{(Eq. 8)}$$

Where:

M = Total Hg mass emissions for the month, (lb);

E_h= Hg mass emissions for hour “h”, from Equation 6 or 7 of this section, (lb); and

n = Number of unit operating hours in the month with valid CE and electrical output data, excluding hours of unit startup, shutdown and malfunction.

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 9, below. For a cogeneration unit, use Equation 5 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \qquad \text{(Eq. 9)}$$

Where:

ER = Monthly Hg emission rate, (lb/MWh);

M = Total mass of Hg emissions for the month, from Equation 8, above, (lb); and

P = Total electrical output for the month, for the hours used to calculate M, (MWh).

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 10 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=1}^{12}(ER_i \times n_i)}{\sum_{i=1}^{12} n_i} \qquad \text{(Eq. 10)}$$

Where:

E_{avg}= Weighted 12-month rolling average Hg emission rate, (lb/MWh);

ER_i= Monthly Hg emission rate, for month “i”, (lb/MWh); and

n = Number of unit operating hours in month “i” with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction.

(3) If a sorbent trap monitoring system is used in lieu of a Hg CEMS, as described in §75.15 of this chapter and in appendix K to part 75 of this chapter, calculate the monthly Hg emission rates using Equations 7 through 9 of this section, except that for a particular pair of sorbent traps, $C_h$in Equation 7 shall be the flow-proportional average Hg concentration measured over the data collection period.

(i) Daily calibration drift (CD) tests and quarterly accuracy determinations shall be performed for Hg CEMS in accordance with Procedure 1 of appendix F to this part. For the CD assessments, you may use either elemental mercury or mercuric chloride (Hg° $HgCl_2$) standards. The four quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using $HgCl_2$standards, as described in section 8.3 of Performance Specification 12–A in appendix B to this part (note: Hg° standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

§ 60.51Da Reporting requirements.

(a) For SO_2, NO_X, PM, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For $SO_2$and $NO_X$the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average $SO_2$and NO_Xemission rates (ng/J or lb/MMBtu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of $SO_2$for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_Xonly), emergency conditions (SO_2only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(9) Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of §60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates (n_i) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (E_o*) and the upper confidence limit for the mean inlet emission rate (E_i*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.

(d) If any standards under §60.43Da are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under §60.48Da(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the SO_2emission standard under §60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of §60.50Da and Method 19 of appendix A of this part; and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, SO_2or NO_Xemissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) For Hg, the following information shall be reported to the Administrator:

(1) Company name and address;

(2) Date of report and beginning and ending dates of the reporting period;

(3) The applicable Hg emission limit (lb/MWh); and

(4) For each month in the reporting period:

(i) The number of unit operating hours;

(ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;

(iii) The monthly Hg emission rate (lb/MWh);

(iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and

(v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for $SO_2$and/or $NO_X$and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

§ 60.52Da Recordkeeping requirements.

The owner or operator of an affected facility subject to the emissions limitations in §60.45Da shall provide notifications in accordance with §60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of §60.7(f).

Browse Previous | Browse Next

Attachment C
to a Part 70 **Operating Permit** Renewal

40 CFR 60, Subpart GG—Standards of Performance for Stationary Gas Turbines

Source Name:	Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
Source Location:	8511 Welborn Road, Mt. Vernon, IN 47620
County:	Posey
SIC Code:	4911 and 3299
Significant Permit Modification No.:	129-26415-00010
Permit Reviewer:	Josiah Balogun
Emission units	Unit No. 3 and 4

Subpart GG—Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000]

§ 60.331 Definitions.

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

(a) *Stationary gas turbine* means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) *Simple cycle gas turbine* means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) *Regenerative cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) *Combined cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) *Emergency gas turbine* means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) *Ice fog* means an atmospheric suspension of highly reflective ice crystals.

(g) *ISO standard day conditions* means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) *Efficiency* means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) *Peak load* means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) *Base load* means the load level at which a gas turbine is normally operated.

(k) *Fire-fighting turbine* means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) *Turbines employed in oil/gas production or oil/gas transportation* means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A *Metropolitan Statistical Area* or *MSA* as defined by the Department of Commerce.

(n) *Offshore platform gas turbines* means any stationary gas turbine located on a platform in an ocean.

(o) *Garrison facility* means any permanent military installation.

(p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, combuster inlet pressure, combuster inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) *Electric utility stationary gas turbine* means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

(r) *Emergency fuel* is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) *Unit operating hour* means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

(t) *Excess emissions* means a specified averaging period over which either:

(1) The NO_Xemissions are higher than the applicable emission limit in §60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.333; or

(3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

(u) *Natural gas* means a naturally occurring fluid mixture of hydrocarbons (*e.g.* , methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur,

680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

(v) *Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

(w) *Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) *Diffusion flame stationary combustion turbine* means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) *Unit operating day* means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_Xemission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_Xemission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_Xemission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_Xemission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NO_Xallowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NO_Xemission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under §60.8 as follows:

Fuel-bound nitrogen (percent by weight)	F (NO_Xpercent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by §60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in theFederal Register.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in §60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO_Xemissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979,Federal Register(44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by §60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

[44 FR 52798, Sept. 10, 1979, as amended at 69 FR 41360, July 8, 2004]

§ 60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_Xemissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_Xemissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of $NO_X$and O_2monitors. As an alternative, a CO_2monitor may be used to adjust the measured NO_Xconcentrations to 15 percent $O_2$by either converting the CO_2hourly averages to equivalent O_2concentrations using Equation F–14a or F–14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O_2, or by using the CO_2readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the $NO_X$and diluent monitors may be performed individually or on a combined basis, *i.e.* , the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO_X) and a percent O_2basis for oxygen; or

(ii) On a ppm at 15 percent O_2basis; or

(iii) On a ppm basis (for NO_X) and a percent CO_2basis (for a CO_2monitor that uses the procedures in Method 20 to correct the NO_Xdata to 15 percent O_2).

(2) As specified in §60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in §60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both $NO_X$and diluent, the data acquisition and handling system must calculate and record the hourly NO_Xemissions in the units of the applicable NO_Xemission standard under §60.332(a), *i.e.* , percent $NO_X$by volume, dry basis, corrected to 15 percent $O_2$and International Organization for Standardization (ISO) standard conditions (if required as given in §60.335(b)(1)). For any hour in which the hourly average O_2concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(iii) If the owner or operator has installed a NO_XCEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_Xemissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable NO_Xemission limit under §60.332, that approved procedure may continue to be used.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO_Xemissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO_XCEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO_Xemissions, may, but is not required to, elect to use a NO_XCEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.

(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control NO_Xemissions may, but is not required to, perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO_Xformation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_Xmode.

(3) For any turbine that uses SCR to reduce NO_Xemissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO_Xemission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in §75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under §60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_Xemission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in §75.19 of this chapter or the NO_Xemission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in §75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard

2377–86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (*i.e.* , if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332). The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.* , flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the

procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(*1*) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*2*) of this section.

(*2*) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*3*) of this section.

(*3*) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (*i.e.* , the maximum total sulfur content of natural gas as defined in §60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in §60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using $NO_X$and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_Xconcentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NO_Xconcentration" is the arithmetic average of the average NO_Xconcentration measured by the CEMS for a given hour (corrected to 15 percent $O_2$and, if required under §60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_Xconcentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_Xconcentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the NO_Xemission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (*i.e.* , daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) *Ice fog.* Each period during which an exemption provided in §60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) *Emergency fuel.* Each period during which an exemption provided in §60.332(k) is in effect shall be included in the report required in §60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each 6-month period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41360, July 8, 2004; 71 FR 9457, Feb. 24, 2006]

§ 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in §60.8, using either

(1) EPA Method 20,

(2) ASTM D6522–00 (incorporated by reference, see §60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine $NO_X$and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for $NO_X$and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_Xconcentrations, normalized to 15 percent O_2, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NO_Xconcentration during the stratification test; or

(B) If each of the individual traverse point NO_Xconcentrations, normalized to 15 percent O_2, is within ±5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{Xo}) corrected to 15 percent O_2shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$NO_X=(NO_{Xo})(P_r/P_o)^{0.5}\ e19\ (Ho-0.00633)(288°K/T_a)^{1.53}$$

Where:

NO_X= emission concentration of NO_Xat 15 percent $O_2$and ISO standard ambient conditions, ppm by volume, dry basis,

NO_{Xo}= mean observed NO_Xconcentration, ppm by volume, dry basis, at 15 percent O_2,

P_r= reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

P_o= observed combustor inlet absolute pressure at test, mm Hg,

H_o= observed humidity of ambient air, g H_2O/g air,

e = transcendental constant, 2.718, and

T_a= ambient temperature, °K.

(2) The 3-run performance test required by §60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in §60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_Xemissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_Xemission limit in §60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control $NO_X$with no additional post-combustion NO_Xcontrol and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522–00 (incorporated by reference, see

§60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 NO_Xemission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in §60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_XCEMS under §60.334(e), then the initial performance test required under §60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NO_Xemission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator elects under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_Xemission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597–94 (Reapproved 1999), D6366–99, D4629–02, D5762–02 (all of which are incorporated by reference, *see* §60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under §60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01 (all of which are incorporated by reference, *see* §60.17); or

(ii) For gaseous fuels, ASTM D1072–80, 90 (Reapproved 1994); D3246–81, 92, 96; D4468–85 (Reapproved 2000); or D6667–01 (all of which are incorporated by reference, see §60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in §60.8 to ISO standard day conditions.

[69 FR 41363, July 8, 2004, as amended at 71 FR 9458, Feb. 24, 2006]

Browse Previous | Browse Next

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (ATSD) for a Part 70 Operating Permit (TITLE V)

Source Background and Description

Source Name:	Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
Source Location:	8511 Welborn Road, Mt. Vernon, IN 47620
County:	Posey
SIC Code:	4911 and 3299
Permit Renewal No.:	129-26415-00010
Permit Reviewer:	Josiah Balogun

On December 3, 2008, the Office of Air Quality (OAQ) had a notice published in the Mount Vernon Democrat, Mount Vernon, Indiana, stating that Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station had applied for a Part 70 Operating Permit (TITLE V) to continue to operate an electric utility generating station. The notice also stated that OAQ proposed to issue a Title V for this operation and provided information on how the public could review the proposed Title V and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this Title V should be issued as proposed.

On December 23, 2008, Bernard Laseke of GZA GeoEnvironmental, Inc submitted comments on the proposed Title V Operating Permit. The comments are summarized in the subsequent pages, with IDEM's corresponding responses.

No changes have been made to the TSD because the OAQ prefers that the Technical Support Document reflects the permit that was on public notice. Changes that occur after the public notice are documented in this Addendum to the Technical Support Document. This accomplishes the desired result, ensuring that these types of concerns are documented and part of the record regarding this permit decision.

The summary of the comments and IDEM, OAQ responses, including changes to the permit (language deleted is shown in ~~strikeout~~ and language added is shown in **bold**) are as follows:

Comment 1: Compliance Determination Requirements Per Section D.1.5 [326 IAC 2-1.1-11]

This provision, as currently worded, would essentially compress the testing cycle to less than two years and continually move the date into less desirable months. Specifically, unit No 1's most recent PM compliance test was performed on May 15, 2007. Requiring a repeat test before May 30. Also, moving the test period prior to May changes the unit's plant duty cycle during which the test will occur. Unit No. 1 and unit No. 2 are base-load plant that achieve maximum operating loads during spring-summer season ("summer peaker"). As such, moving the prior to May moves it into a period that does not coincide with peak (Maximum) load duty. (The point being that the unit must be at or with 5% of maximum operating load for a valid test point.) Our legal representative (Plews Shadley Racher & Braun) reviewed this issue with IDEM's Compliance Date Section (Dave Cline) who concurred on the following points: IDEM policy does not prescribe that the repeat testing requirement be written to occur before certain date, only that it occur on a 2-year cycle. IDEM policy accommodates the Permittee certain flexibility to coincide testing and scheduled maintenance outages that remain consistent within a set schedule. IDEM policy would accommodate testing to occur within the second quarter of every second

year. (See attached.) Accordingly, the proposed revised language for Condition D.1.5 is shown below (current draft version shown in strikeout and proposed revised version shown below it):

- ~~D.1.5 Testing Requirements [326 IAC 2-1.1-11]: In order to determine compliance with PM limitation, the Permittee shall perform PM testing before May 2009 on the fabric filter controlling the dry-bottom pulverized coal-fire boiler, identified as Unit 1 utilizing methods as approved by the Commissioner. This test shall be repeated at least once every two (2) years from the date of this valid compliance demonstration. Testing shall be conducted in accordance with Section C- Performance Testing.~~

- **D.1.5 Testing Requirements [326 IAC 2-1.1-11]: In order to determine compliance with the PM limitation, the Permittee shall perform PM testing during the Second Quarter of 2009 on the fabric filter controlling the dry-bottom pulverized coal-fired boiler, identified as Unit 1, utilizing methods as approved by the Commissioner. This test shall be repeated by the Second Quarter of every second year following this valid compliance demonstration. Testing shall be conducted in accordance with Section C- Performance Testing.**

- ~~D.2.7 Testing Requirements [326 IAC 2-1.1-11]: In order to determine compliance with Conditions D.2.1 and D.2.2, the Permittee shall perform PM testing before April 2010 on the electrostatic precipitator (ESP) controlling the dry-bottom pulverized coal-fire boiler, identified as Unit 2 utilizing methods as approved by the Commissioner. This test shall be repeated at least once every two (2) years from the date of this valid compliance demonstration. Testing shall be conducted in accordance with Section C- Performance Testing.~~

- **D.2.7 Testing Requirements [326 IAC 2-1.1-11]: In order to determine compliance with Conditions D.2.1 and D.2.2, the Permittee shall perform PM testing during the Second Quarter of 2010 on the electrostatic precipitator (ESP) controlling the dry-bottom pulverized coal-fired boiler, identified as Unit 2, utilizing methods as approved by the Commissioner. This test shall be repeated by the Second Quarter of every second year following this valid compliance demonstration. Testing shall be conducted in accordance with Section C- Performance Testing.**

Response 1: IDEM agrees with SIGECO, Conditions D.1.5 and D.2.7 have been revised as stated above in the permit.

Comment 2: Conditions D.1.13(a) and D.2.14(b) are inconsistent, the permit mentions item (1) and (2) while listing (1) through (4). Also Section D.1.13(b) and D.2.14(b) are inconsistent, the permit mentions item (2) through (3) while listing (1) through (2).

D.1.13 Record Keeping Requirements

(a) To document compliance with Section C - Maintenance of Continuous Opacity Monitoring Equipment, and the particulate matter and opacity requirements in Conditions D.1.2, D1.8, D.1.5 and D.1.10, the Permittee shall maintain records in accordance with (1) through ~~(2)~~ **(4)** below. Records shall be complete and sufficient to establish compliance with the limits in Condition D.1.2.

(b) To document compliance with the SO_2 requirements in Conditions D.1.1, D.1.8, D.1.9 and D.1.12, the Permittee shall maintain records in accordance with (1) through ~~(3)~~ **(2)** below. Records shall be complete and sufficient to establish compliance with the applicable SO_2 limit(s) as required in Conditions D.1.1 and D.1.8. The Permittee shall

maintain records in accordance with **(1) and** (2) ~~and (3)~~ below during SO_2 CEM system downtime.

.....

D.2.14 Record Keeping Requirement

(a) To document compliance with Section C - Maintenance of Continuous Opacity Monitoring Equipment, and the particulate matter and opacity requirements in Conditions D.2.1, D.2.2, D.2.7, D.2.10, and D.2.12, the Permittee shall maintain records in accordance with (1) through ~~(2)~~ **(4)** below. Records shall be complete and sufficient to establish compliance with the limits in Conditions D.2.1 and D.2.2.

(b) To document compliance with SO_2 Conditions D.2.1(b), D.2.2, D.2.3, D.2.10, D.2.11 and D.2.13, the Permittee shall maintain records in accordance with (1) through ~~(3)~~ **(2)**below. Records shall be complete and sufficient to establish compliance with the SO_2 limit(s) as required in Conditions D.2.1(b), D.2.3 and D.2.10. The Permittee shall maintain records in accordance with **(1) and** (2) ~~and (3)~~ below during SO_2 CEM system downtime.

.....

Response : The typos in Conditions D.1.13(a), D.1.13(b), D.2.14(a) and D.2.14(b) have been corrected in the permit.

Comments 3: Eliminate D.3.7(d) since this unit (combustion turbine) does not fire coal.

D.3.7 Record Keeping Requirement

(a) To document compliance with Condition D.3.1, the Permittee shall maintain records of the following:

.....

(d) To document compliance with Condition ~~D.3.7~~ **D.3.6**- Visible Emission Notation, the Permittee shall maintain daily records of the visible emission notations of the dry-bottom pulverized coal-fire boiler stack exhaust. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that day).

Response 3: The turbine uses distillate oil (No.2 fuel oil) as a backup. Therefore, it is necessary to monitor the operations of the turbine when using distillate oil #2 in the turbine. No changes are made to the permit.

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a

Part 70 Operating Permit Renewal

Source Background and Description

Source Name:	Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station
Source Location:	8511 Welborn Road, Mt. Vernon, IN 47620
County:	Posey
SIC Code:	4911 and 3299
Permit Renewal No.:	129-26415-00010
Permit Reviewer:	Josiah Balogun

The Office of Air Quality (OAQ) has reviewed the operating permit renewal application from Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station relating to the operation of an electric utility generating station.

History

On April 14, 2008, Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station submitted an application to the OAQ requesting to renew its operating permit. Southern Indiana Gas and Electric Company (SIGECO) A.B. Brown Generating Station was issued a Part 70 Operating Permit on December 15, 2004.

Permitted Emission Units and Pollution Control Equipment

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

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

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

(d) One (1) simple cycle natural gas-fired combustion turbine, designated as unit ABB No. 4, with constructed 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV) with inlet fogger for power augmentation during high ambient temperature operation, with dry low-NOx combustion, with continuous emissions monitoring (CEM) system for nitrogen oxides (NO_X) and carbon monoxide (CO), exhausting to stack No.4

(e) A coal storage and handling system, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit 2 boiler, with a maximum throughput of 600 tons of coal per hour, consisting of the following equipment:

(1) One (1) railcar and truck unloading station with particulate emissions controlled by enclosure, with a drop point to the coal pile.

(2) One (1) storage pile, having a storage capacity of 700,000 tons, with fugitive emissions controlled by a watering system.

(3) An enclosed conveyor system, with a maximum feed rate of 600 tons per hour, with the transfer points underground or enclosed by buildings, and exhausting inside the transfer buildings or powerhouse.

(4) Twelve (12) enclosed coal pulverizers, each with a maximum capacity of twenty (20) tons of coal per hour, and exhausting to the boilers

(f) A lime storage and handling system, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit 2 boiler, consisting of the following equipment:

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

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

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

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

(g) A soda ash storage and handling system, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit 2 boiler, consisting of the following equipment:

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

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

(h) The wet fly and bottom ash handling system was installed and expanded with start-up dates of 1979 (installed with Unit No. 1) and 1985 (installed with Unit No. 2). The dry fly ash (DFA) system was subsequently added to accommodate the option for product recovery of DFA material through a separate storage, handling, and barging operation to an off-site location. The DFA handling system interfaces with the existing wet ash system at the Hydroveyor. (Hydroveyor No. 1 for A. B. Brown No. 1 and Hydroveyor No. 2 for A.

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

(i) Scrubber sludge handling, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit 2 boiler, with wet sludge conveyed to haul trucks.

Emission Units and Pollution Control Equipment Constructed and/or Operated without a Permit

There are no unpermitted facilities operating at this source during this review process.

Emission Units and Pollution Control Equipment Removed From the Source

No equipment has been removed from this facility during this review process.

Insignificant Activities
The source also consists of the following insignificant activities, as defined in 326 IAC 2-7-1(21):

(1) Natural gas-fired combustion sources with heat input equal to or less than ten million (10,000,000) Btu per hour:

(a) One (1) natural gas-fired auxiliary boiler, identified as Unit No. 8, constructed in 1977, with a heat input capacity of 0.0335 MMBtu per hour and exhausting to stack #5.

(2) Combustion source flame safety purging on startup.

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

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

(5) The following VOC and HAP storage containers:

(A) Storage tanks with capacity less than or equal to 1,000 gallons and annual throughput less than 12,000 gallons.

(B) Vessels storing lubricating oils, hydraulic oils, machining oils, and machining fluids.

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

(7) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6.[326 IAC 8-3-2] [326 IAC 8-3-5]

(8) The following equipment related to manufacturing activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

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

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

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

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

(13) Heat exchanger cleaning and repair.

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

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

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

(17) Asbestos abatement projects regulated by 326 IAC 14-10.

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

(19) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including catch tanks, temporary liquid separators, tanks, and fluid handling equipment.

(20) Blowdown for any of the following: sight glass; boiler; compressors; pumps; and cooling tower.

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

(22) Emergency generators as follows: Diesel generators not exceeding 1600 horsepower.

(23) Other emergency equipment as follows: Stationary fire pumps.

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

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

(26) Farm operations.

(27) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(a) Fuel Oil Storage Tank #1

(b) Fuel Oil Storage Tank #2

(c) Boiler Chemical Cleaning waste evaporation

(d) Ash pond and ash pond maintenance, with water cover or vegetation sufficient to prevent ash re-entrainment.

(e) Facility waste oil incineration.

Existing Approvals

Since the issuance of the Part 70 Operating Permit 129-6848-00010 on December 15, 2004, the source has constructed or has been operating under the following approvals as well:

(a) Administrative Amendment No. 129-21413-00010 issued on July 21, 2005; and

(b) Acid rain Renewal No. 129-19748-00010 issued on May 9, 2006.

All terms and conditions of previous permits issued pursuant to permitting programs approved into the state implementation plan have been either incorporated as originally stated, revised, or deleted by this permit. All previous registrations and permits are superseded by this permit.

Enforcement Issue

There are no enforcement actions pending.

Emission Calculations

The calculations submitted by the applicant have been verified and found to be accurate and correct.

County Attainment Status

The source is located in Posey County

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective June 15, 2004, for the 8-hour ozone standard.[1]
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
Pb	Not designated.
[1]Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005. Unclassifiable or attainment effective April 5, 2005, for PM2.5.	

(a) Ozone Standards

(1) On October 25, 2006, the Indiana Air Pollution Control Board finalized a rule revision to 326 IAC 1-4-1 revoking the one-hour ozone standard in Indiana.

(2) On September 6, 2007, the Indiana Air Pollution Control Board finalized a temporary emergency rule to re-designate Allen, Clark, Elkhart, Floyd, LaPorte, St. Joseph as attainment for the 8-hour ozone standard.

(3) On November 9, 2007, the Indiana Air Pollution Control Board finalized a temporary emergency rule to re-designate Boone, Clark, Elkhart, Floyd, LaPorte, Hamilton, Hancock, Hendricks, Johnson, Madison, Marion, Morgan, Shelby, and St. Joseph as attainment for the 8-hour ozone standard.

(4) Volatile organic compounds (VOC) and Nitrogen Oxides (NOx) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NOx emissions are considered when evaluating the rule applicability relating to ozone. Posey County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) PM2.5
Posey County has been classified as attainment for PM2.5. On May 8, 2008 U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for PM2.5 emissions, and the effective date of these rules was July 15th, 2008. Indiana has three years from the publication of these rules to revise its PSD rules, 326 IAC 2-2, to include those requirements. The May 8, 2008 rule revisions require IDEM to regulate PM10 emissions as a surrogate for PM2.5 emissions until 326 IAC 2-2 is revised.

(c) Other Criteria Pollutants
Posey County has been classified as attainment or unclassifiable in Indiana for all criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(d) Fugitive Emissions
Since this type of operation is in one of the twenty-eight (28) listed source categories under 326 IAC 2-2 or 326 IAC 2-3, fugitive emissions are counted toward the determination of PSD and Emission Offset applicability.

Unrestricted Potential Emissions

This table reflects the unrestricted potential emissions of the source.

Pollutant	tons/year
PM	greater than 100
PM_{10}	greater than 100
SO_2	greater than 100
VOC	less than 100
CO	greater than 100
NO_x	greater than 100

HAPs	tons/year
Single HAP	greater than 10
Total HAPs	greater than 25

The Permittee has agreed that they are major for Part 70 Permits 326 IAC 2-7, Prevention of Significant Deterioration (PSD) 326 IAC 2-2, for PM10, SO2, CO, NOx and Hazardous Air Pollutants 326 IAC 20.

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM10, SO2, CO, and NOx are equal to or greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

(b) The potential to emit (as defined in 326 IAC 2-7-1(29)) of all other criteria pollutants are less than 100 tons per year.

(c) The potential to emit (as defined in 326 IAC 2-7-1(29)) of any single HAP is equal to or greater than ten (10) tons per year and/or the potential to emit (as defined in 326 IAC 2-7-1(29)) of a combination of HAPs is equal to or greater than twenty-five (25) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

(d) Since this type of operation is one of the twenty-eight (28) listed source categories under 326 IAC 2-7, fugitive emissions are counted toward the determination of Part 70 applicability.

Part 70 Permit Conditions

This source is subject to the requirements of 326 IAC 2-7, pursuant to which the source has to meet the following:

(a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.

(b) Monitoring and related record keeping requirements which assume that all reasonable information is provided to evaluate continuous compliance with the applicable requirements.

Potential to Emit After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of this Part 70 permit renewal, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

	Potential to Emit						
Emission Unit	**PM (tons/yr)**	**PM10/ PM2.5 (ton/yr)**	**SO2 (tons/yr)**	**VOC (tons/yr)**	**CO (tons/yr)**	**NOX (tons/yr)**	**HAPs (tons/yr)**
Coal fired-boiler Unit 1	> 100	> 100	> 100	< 100	> 100	> 100	Single HAP > 9, Total HAPs > 24
Coal fired-boiler Unit 2	> 100	> 100	> 100	< 100	> 100	> 100	
Soda ash Storage and handling system	3.84	3.84	0	0	0	0	0
Lime Storage and handling system	3.84	3.84	0	0	0	0	0
Coal Storage and handling system	8.02	8.02	0	0	0	0	0
Turbine Unit AAB CT No.3	9.7	9.7	39.7	2.0	66.0	39.9	1.0
Turbine Unit AAB No.4	21.9	21.9	17.06	7.45	224.6	133.9	2.9
Auxiliary Boiler Unit # 8	0	0.001	0	0.001	0.012	0.015	neg
Total Emissions	> 100	> 100	> 100	< 100	> 100	> 100	Single greater than 10 Total greater than 25

Note:
Lime storage and handling system and soda ash storage system limited emissions are based on 326 IAC 6-3-2(e)(3), assuming the process weight rate is 200 tons per hour.
Coal Storage and handling system limited emissions are based on 326 IAC 6-3-2(e)(3) with a process weight rate of 600 tons per hour.

(a) This existing stationary source is major for PSD because the emissions of at least one regulated pollutant is greater than one hundred (>100) tons per year, and it is one of the twenty-eight (28) listed source categories.

(b) Fugitive Emissions
Since this type of operation is in one of the twenty-eight (28) listed source categories under 326 IAC 2-2, fugitive emissions are counted toward the determination of PSD applicability.

Federal Rule Applicability

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to existing emission units that involve a pollutant-specific emission unit and meet the following criteria:

(1) has a potential to emit before controls equal to or greater than the major source threshold for the pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant; and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to each existing emission unit and specified pollutant subject to CAM:

Emission Unit / Pollutant	Control Device Used	Emission Limitation (Y/N)	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	CEMS Applicable (Y/N)	CAM Applicable (Y/N)	Large Unit (Y/N)
Unit No. 1 (PM)	Y	Y	>100	> 100	100	N	Y	Y
Unit No. 2 (PM)	Y	Y	>100	> 100	100	N	Y	Y
Unit No. 3 (PM)	N	N	< 100	N/A	100	N	N	N
Unit No. 4 (PM)	N	N	< 100	N/A	100	N	N	N
Unit No. 3 (SO2)	N	Y	< 100	N/A	100	Y	N	N
Unit No. 3 (NOx)	N	Y	< 100	N/A	100	Y	N	N
Unit No. 4 (SO2)	N	Y	< 100	N/A	100	Y	N	N
Unit No. 4 (NOx)	N	Y	> 100	N/A	100	Y	N	Y
Unit No. 4 (CO)	N	N	> 100	N/A	100	N	N	Y

Note: N/A (Not applicable)

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are applicable to Unit No.1 and Unit No.2 for PM emissions upon issuance of the Title V Renewal. A CAM plan will be incorporated into this Part 70 permit renewal.

The PTE of SO2 and NOx for turbines, identified as Unit 3 and 4 are greater than 100 tons per year. CAM is not applicable to the two (2) turbines because the turbines are subject to compliance emission monitoring systems (CEMS) method for compliance.

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are not applicable to the two (2) turbines for SO2 and NOx as part of this Part 70 permit renewal.

(b) 326 IAC 12 and 40 CFR 60, Subpart D-Standard of Performance for Fossil - Fuel Steam Generators For Which Construction is Commenced After August 17, 1971.

The pulverized coal - fired boiler, identified as Unit 1 is subject to the requirements of the New Source Performance Standard, 40 CFR 60, Subpart D, Standard of Performance for Fossil - Fuel Steam Generators For Which Construction is Commenced After August 17, 1971 because the pulverized coal - fired boiler was constructed in 1974, which is after August 17, 1971, which is the applicability date for this rule and the pulverized coal -

fired boiler has a heat input capacity of greater 250 million Btu/hour. The specific facility subject to this rule includes the following.

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

The pulverized coal - fired boiler, identified as Unit 1 is subject to the following sections of 40 CFR Part 60, Subpart D.

(1) 40 CFR 60.40
(2) 40 CFR 60.41
(3) 40 CFR 60.42
(4) 40 CFR 60.43
(5) 40 CFR 60.44
(6) 40 CFR 60.45 and
(7) 40 CFR 60.46

(c) 326 IAC 12 and 40 CFR 60, Subpart Da - Standard of Performance for Electric Utility Steam Generating Units For Which Construction is Commenced After September 18, 1978.

The pulverized coal-fired boiler, identified as Unit No. 2 is subject to the requirements of the New Source Performance Standard, 40 CFR 60, Subpart Da, Standard of Performance for Electric Utility Steam Generating Units For Which Construction is Commenced After September 18, 1978 because the boiler was constructed in 1979, which is after September 18, 1978, which is the applicability date for this rule and the boiler has a heat input capacity of greater 250 million Btu/hour. The specific facility subject to this rule includes the following.

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

The pulverized coal-fired boiler, identified as Unit No. 2 is subject to the following sections of 40 CFR Part 60, Subpart Da.

(1) 40 CFR 60.40da
(2) 40 CFR 60.41da
(3) 40 CFR 60.42dc

(4) 40 CFR 60.43da
(5) 40 CFR 60.44da
(6) 40 CFR 60.45da
(7) 40 CFR 60.46da
(8) 40 CFR 60.47da
(9) 40 CFR 60.48da
(10) 40 CFR 60.49da
(11) 40 CFR 60.50da
(12) 40 CFR 60.51da
(13) 40 CFR 60.52da

(d) 326 IAC 12 and 40 CFR 60, Subpart GG-Standard of Performance for Stationary Gas Turbines.

The two (2) boilers, identified as Unit ABB CT No 3 and Unit ABB No 4 are subject to the requirements of the New Source Performance Standard, 40 CFR 60, Subpart GG, Standard of Performance for Stationary Gas Turbines because the boilers are constructed in 1989 and 2001, respectively, which is after October 3, 1977, which is the applicability date for this rule and the boilers have a heat input capacity of greater 10 million Btu/hour, each. The specific facility subject to this rule includes the following.

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

(2) One (1) simple cycle natural gas-fired combustion turbine, designated as unit ABB No. 4, with constructed 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV) with inlet fogger for power augmentation during high ambient temperature operation, with dry low-NOx combustion, with continuous emissions monitoring (CEM) system for nitrogen oxides (NO_X) and carbon monoxide (CO), exhausting to stack No.4

The two (2) boilers, identified as Unit ABB CT No 3 and Unit ABB No 4 are subject to the following sections of 40 CFR Part 60, Subpart GG.

(1) 40 CFR 60.330
(2) 40 CFR 60.331
(3) 40 CFR 60.332
(4) 40 CFR 60.333
(5) 40 CFR 60.334
(6) 40 CFR 60.335

(e) The coal storage and handling is not subject to the requirements of the New Source Performance Standard, 326 IAC 12, (40 CFR 60, Subpart Y (Standards of Performance for Coal Preparation Plants)) because the operations don't meet the definition of a coal preparation plant. Only conveying and storage is performed onsite. All coal is crushed before delivery.

(f) The lime handling is not subject to the requirements of the New Source Performance Standard, 326 IAC 12 (40 CFR 60, Subpart OOO, (Standards of Performance for Nonmetallic Mineral Processing Plants) because the source does not do any crushing of lime, only storage and conveying.

(g) The oil and gasoline storage tanks are not subject to the requirements of the New Source Performance Standard, 326 IAC 12 (40 CFR 60, Subpart K, (Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and prior to May 19, 1978); Subpart Ka (Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and prior to July 23, 1984) because all of the tanks were installed prior to 1984. The exact date of installation is not known; however, Subparts K and Ka specifically exempt Nos. 2 through 6 fuel oils from the definition of Petroleum Liquids.

(h) There are no National Emission Standards for Hazardous Air Pollutants (NESHAP) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) included in this permit renewal.

State Rule Applicability - Entire Source

326 IAC 2-2 (Prevention of Significant Deterioration(PSD))
This source is one of the 28 listed source categories and has potential to emit of at least one attainment pollutant greater than 100 tons per year before August 7, 1977. This source was a major source pursuant to 326 IAC 2-2 (PSD), prior to August 7, 1977.

1979 Modification
The dry bottom, pulverized coal-fired boiler, identified as Unit No. 2 constructed in 1979 has uncontrolled PM and PM_{10} emissions greater than 25 and 15 tons per year respectively. Pursuant to PSD (65) 1355 issued on February 22, 1979 the emissions from Unit No. 2 for PM and PM10 shall not exceed 0.03 pounds per million Btu (MMBtu) of energy input, each.

The dry bottom, pulverized coal-fired boiler, identified as Unit No. 2 constructed in 1979 has uncontrolled NOx emissions greater than 40 tons per year . Pursuant to PSD (65) 1355 issued on February 22, 1979 the emissions from Unit No. 2 for NOx shall not exceed 0.60 pounds per million Btu (MMBtu) of energy input.

The dry bottom, pulverized coal-fired boiler, identified as Unit No. 2 constructed in 1979 has uncontrolled SO2 emissions greater than 40 tons per year. Pursuant to PSD (65) 1355 issued on February 22, 1979 the emissions from Unit No. 2 for SO2 shall not exceed 0.69 pounds per million Btu (MMBtu) of energy input.

Pursuant to PSD (65) 1355 issued on February 22, 1979, BACT emissions control shall be used as follows:

(a) The SO2 emissions shall be controlled by a scrubber having a minimum control efficiency of 90.0%

(b) The stack gas particulate emissions shall be controlled by an electrostatic precipitator having a minimum collection efficiency of 99.6% when burning coal with maximum ash content of 10%, a minimum sulfur content of 2.5% and a minimm heat content of 11, 000 Btu per pound.

1989 Modification
The simple-cycle natural gas-fired combustion turbine, identified as Unit No. 3 constructed in 1989 has uncontrolled NOx and SO2 emissions greater than 40 tons per year, each. Pursuant to Construction Permit PC (65) 1802 issued on November 6, 1989, the NOx and SO2 emissions from Unit No. 3 shall less than 40 tons per twelve (12) consecutive month period, each, with compliance determined at the end of each month. Compliance with the limit above will limit the NOx and SO2 emissions to less than 40 tons per year, each and render 326 IAC 2-2 not applicable to the 1989 modification.

The simple-cycle combustion turbine shall use natural gas as the primary fuel and No. 2 distillate oil as an emergency backup fuel only. Pursuant to 40 CFR 331(r), emergency fuel is defined as a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine. The quantity of No. 2 distillate fuel oil used shall not exceed 1,893,000 gallon per twelve (12) consecutive month period, with compliance determined at the end of each month and the SO_2 and NOx emissions shall not exceed 0.042 pounds per gallon each.

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

2001 Modification
The gas turbine generator, identified as Unit No. 4 constructed in 2001 has uncontrolled PM_{10} emissions greater than 15 tons per year. Pursuant to SSM 129-14021-00010 issued on November 16, 2001 the PM10 emissions from Unit No. 4 shall not exceed 0.005 pounds per million Btu (MMBtu) of energy input.

Pursuant to SSM 129-14021-00001, issued on November 16, 2001, the gas turbine generator, identified as ABB Unit 4 shall use a dry low-NOx combustors in conjuction with natural gas and during nornal simply cycle operation (i.e., steady-state operating condition), the NOx emissions from combustion turbine when buring natural gas shall be less than 9.0 ppmvd corrected to fifteen (15) percent oxygen, based on a twenty four (24) operating hour averaging period, which is equivalent to 36 pounds per hour.

Pursuant to SSM 129-14021-00001, isued on November 16, 200, the annual NO_X emissions from ABB No. 4 burning natural gas shall be less than 132.06 tons per twelve (12) consecutive month period, excluding startup and shutdown emissions, with compliance determined at the end of each month.

Pursuant to SSM 129-14021-00001, issued November 16, 2001, the gas turbine generator, identified as ABB Unit 4 shall comply with the following:

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

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

Pursuant to SSM 129-14021-00001, issued November 16, 2001, the annual CO emissions from gas turbine generator, identified as ABB Unit 4 burning natural gas shall be less than 221.52 tons per twelve (12) consecutive month period, excluding startup and shutdown emissions, with compliance determined at the end of each month.

Startup and Shutdown Limitations for Combustion Turbine (326 IAC 2-2)
Pursuant to SSM 129-14021-00001, issued November 16, 2001, the ABB No. 4 shall meet the following startup and shutdown conditions:

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

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

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

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

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

(3) The CO emissions from ABB No. 4 stack shall be less than 65 pounds per event. ABB No. 4 shall emit less than 14.9 tons of CO during startup and shutdown per twelve (12) consecutive month period, with compliance determined at the end of each month.

326 IAC 2-6 (Emission Reporting)
This source is subject to 326 IAC 2-6 (Emission Reporting) because it is required to have an operating permit under 326 IAC 2-7, Part 70 program. Pursuant to this rule, the Permittee shall submit an emission statement certified pursuant to the requirements of 326 IAC 2-6. In accordance with the compliance schedule specified in 326 IAC 2-6-3, an emission statement must be submitted annually by July 1 and every year after Therefore, the next emission statement for this source must be submitted by July 1, 2009. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 5-1 (Opacity Limitations)
Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Exemptions), opacity shall meet the following, unless otherwise stated in the 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.

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

326 IAC 7-3 (Ambient Monitoring)
The Permittee shall operate continuous ambient sulfur dioxide air quality monitors and a meteorological data acquisition system according to a monitoring plan submitted. 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).

326 IAC 10-4 (NO_X Budget Trading Program)
Pursuant to 326 IAC 10-4-2(16), each of the boilers Units 1 and 2 and the combustion turbine CT No. 3 is considered an “electricity generating unit (EGU)” because it commenced operation before January 1, 1997, and served a generator during 1995 or 1996 that had a nameplate capacity greater than twenty-five (25) megawatts that produced electricity for sale under a firm contract to the electric grid. The combustion turbine No. 4 is considered an “electricity generating unit (EGU)” because it commenced operation on or after January 1, 1999, and serves a generator at any time that has a nameplate capacity greater than twenty-five (25) megawatts that produces

electricity for sale under a firm contract to the electric grid. Pursuant to 326 IAC 10-4-1(a)(1), an "EGU" is a NO_X budget unit. Because this source meets the criteria of having one (1) or more NO_X budget units, it is a NO_X budget source. The Permittee shall be subject to the requirements of this rule. The NO_X budget permit is in section F of the Part 70 permit. The Technical Support Document for the NO_X budget permit is provided as Appendix A to this Technical Support Document.

Pursuant to 326 IAC 10-4-12(c), the Permittee has installed the appropriate monitoring systems and completed all certification tests as required by 326 IAC 10-4-12(b)(1) through (3) on or before May 1, 2003.

State Rule Applicability – Individual Facilities

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes) the coal storage and handling system operating at a process weight rate of 600 tons per hour, the concentration of particulate in discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1000) pounds of gases.

The water mist curtain shall be in operation at all times the coal storage and handling system (railcar and truck unloading) is in operation, in order to comply with this limit.

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

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

$E = 4.10\ P^{0.67}$ where E = rate of emission in pounds per hour and
P = process weight rate in tons per hour

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

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

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

326 IAC 5-1-3 (Temporary Alternative Opacity Limitations)

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

(b) If this facility cannot meet the opacity limitation of 326 IAC 5-1-3(a), the Permittee may submit a written request to IDEM, OAQ, for a temporary alternative opacity limitation in accordance with 326 IAC 5-1-3(e). The Permittee must demonstrate that the alternative limit is needed and justifiable.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 6-3-2, the particulate emissions from the insignificant activities, brazing equipment, cutting torches, soldering equipment, and welding equipment shall be limited by the following equation:

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

$$E = 4.10\ P^{0.67}$$

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

326 IAC 6-2-3 (Particulate Emissions Limitations for Indirect Heating Facilities)
The dry bottom, pulverized coal-fired boilers, identified as Unit 1 and one (1) auxiliary boiler, identified as Unit #8 are subject to 326 IAC 6-2-3 (Particulate Emissions for Sources of indirect Heating) because they were constructed before 1983. Pursuant to this rule, the particulate matter emissions from the dry bottom, pulverized coal-fired boilers, identified as Unit 1, Unit 2 and unit #8 shall not exceed 1.16 lb/MMBtu, each.

$$\text{Limit} = \frac{C \times a \times h}{76.5 \times Q^{0.75} \times N^{0.25}} = 1.16 \text{ lb/MMBtu}$$

Where:

C = 50 micrograms/cu. Meter, maximum ground level concentration
Q = 2551.5 MMBtu/hr, heat input rate
N = 1 number of stacks
a = 0.8 dimensionless, plume rise factor
h = 496 ft, average stack height

Pursuant to 40 CFR 60.42, the particulate matter (PM) emission limit for the boilers are 0.1 lbs/MMBtu, each.

Therefore, the PM limit for the dry bottom, pulverized coal-fired boiler and the auxiliary boiler, from 40 CFR 60, Subpart D are more stringent than the PM limit from 326 IAC 6-2-3. Therefore, the dry bottom, pulverized coal-fired boiler and the auxiliary boiler are exempt from the requirements of 326 IAC 6-2-3.

326 IAC 6-2-4 (Particulate Emissions Limitations for Indirect Heating Facilities)
The dry bottom, pulverized coal-fired boilers, identified as Unit 1 is subject to 326 IAC 6-2-4 (Particulate Emissions for Sources of indirect Heating) because they were constructed in 1986.

Pursuant to this rule, the particulate matter emissions from dry bottom, pulverized coal-fired boilers, identified as Unit 1 shall be limited as follows:

$$Pt = \frac{1.09}{Q^{0.26}} = 0.14$$

Where:

Pt = Pounds of particulate matter emitted per million Btu (lb/MMBtu) heat input; and
Q = Total source maximum operating capacity (MMBtu/hr).

Pursuant to 40 CFR 60.42, the particulate matter (PM) emission limit for the boiler is 0.1 lbs/MMBtu.

Therefore, the PM limit for the dry bottom, pulverized coal-fired boiler from 40 CFR 60, Subpart D is more stringent than the PM limit from 326 IAC 6-2-3. Therefore, the dry bottom, pulverized coal-fired boiler, identified as Unit #2 is exempt from the requirements of 326 IAC 6-2-3.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The operation of gas turbine generator, identified as ABB Unit 4 will emit greater than ten (10) tons per year for a single HAP. However, pursuant to SSM 129-14021-00001, issued on November 16, 2001, the formaldehyde emissions from the ABB No. 4 combustion turbine shall not exceed 0.00142 lb/MMBtu. This will limit the formaldehyde emissions from ABB No. 4 to be less than 10 tons per year and render requirements of 326 IAC 2-4.1 not applicable to ABB No. 4.

326 IAC 7-1.1-2 Sulfur Dioxide (SO_2)
Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), the SO_2 emissions from the Boiler, identified as Unit 1 shall not exceed 6.0 pounds per million Btu (lbs/MMBtu).

326 IAC 7-1 Sulfur Dioxide Emission Limitations
Pursuant to 326 IAC 7-1.1-2, the sulfur dioxide emissions from the turbines, identified as Unit 3 and Unit 4 shall be limited to 0.5 pounds per million Btu, each, when firing distillate oil, the backup fuel.

326 IAC 8-3-2 (Cold Cleaner Operation)
Pursuant to 326 IAC 8-3-2 (Cold Cleaner Operation), for cold cleaning facilities constructed after January 1, 1980, the Permittee shall:

(a) Equip the cleaner with a cover;

(b) Equip the cleaner with a emissions unit for draining cleaned parts;

(c) Close the degreaser cover whenever parts are not being handled in the cleaner;

(d) Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases;

(e) Provide a permanent, conspicuous label summarizing the operation requirements;

(f) Store waste solvent only in covered containers and not dispose of waste solvent or transfer it to another party, in such a matter that greater than twenty percent (20%) of the waste solvent (by weight) can evaporate into the atmosphere.

362 IAC 8-3-5 (Cold Cleaner Degreaser Operation and Control)

(a) Pursuant to 326 IAC 8-3-5(a) (Cold Cleaner Degreaser Operation and Control), for cold cleaner degreaser operations without remote solvent reservoirs constructed after July 1, 1990, the Permittee shall ensure that the following control equipment requirements are met:

(1) Equip the degreaser with a cover. The cover must be designed so that it can be easily operated with one (1) hand if:

(A) The solvent volatility is greater than two (2) kiloPascals (fifteen (15) millimeters of mercury or three-tenths (0.3) pounds per square inch) measured at thirty-eight degrees Celsius ($38^{O}C$) (one hundred degrees Fahrenheit ($100^{O}F$));

(B) The solvent is agitated; or

(C) The solvent is heated

(2) Equip the degreaser with a emissions unit for draining cleaned articles. If the solvent volatility is greater than four and three-tenths (4.3) kiloPascals (thirty-two (32) millimeters of mercury) or six-tenths (0.6) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F)), then the drainage emissions unit must be internal such that articles are enclosed under the cover while draining. The drainage emissions unit may be external for applications where an internal type cannot fit into the cleaning system.

(3) Provide a permanent, conspicuous label which lists the operating requirements outlined in subsection (b).

(4) The solvent spray, if used, must be a solid, fluid stream and shall be applied at a pressure which does not cause excessive splashing.

(5) Equip the degreaser with one (1) of the following control devices if the solvent volatility is greater than four and three-tenths (4.3) kiloPascals (thirty-two (32) millimeters of mercury) or six-tenths (0.6) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F)), or if the solvent is heated to a temperature greater than forty-eight and nine-tenths degrees Celsius (48.9^{O}C) (one hundred twenty degrees Fahrenheit (120°F)):

(A) A freeboard that attains a freeboard ratio of seventy-five hundredths (0.75) or greater.

(B) A water cover when solvent is used is insoluble in, and heavier than, water.

(C) Other systems of demonstrated equivalent control such as a refrigerated chiller of carbon adsorption. Such systems shall be submitted to the U.S. EPA as a SIP revision.

(b) Pursuant to 326 IAC 8-3-5(b) (Cold Cleaner Degreaser Operation and Control), the Permittee shall ensure that the following operating requirements are met:

(1) Close the cover whenever articles are not being handled in the degreaser.

(2) Drain cleaned articles for at least fifteen (15) seconds or until dripping ceases.

(3) Store waste solvent only in covered containers and prohibit the disposal or transfer of waste solvent in any manner in which greater than twenty percent (20%) of the waste solvent by weight could evaporate.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions, however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination

Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

The compliance monitoring requirements applicable to this source are as follows:

Control	Parameter	Frequency	Value	Excursions and Exceedances
Fabric Filter to control Unit #1	Gas-side pressure drop	Continuous	6.0 in. H2O (full load operating condition)	Total gas-side ΔP is 9-in. (H_2O) from air preheater outlet to ID fan inlet (full load). The gas-side ΔP across the FF is 6-in. H_2O (full load). The chamber bags begin pulsing when ΔP reaches 6.5-in. H_2O in and ceases when ΔP reaches 5.5-in. H_2O. Chamber trip occurs when ΔP reaches 10-in. H_2O for + 30 seconds. The ID fan trip occurs when ΔP reaches 12-in. H_2O for + 2 seconds.
	Visible Emissions	Continuous	COM	Continuous opacity monitoring measurements
Electrostatic Precipitator to control Unit #2	T-R set in service and T-R electrical values of Primary and secondary voltages and Current.	Continuous	N/A	The number of T-R sets in services and their electrical performance are continuously measured.
	Visible Emissions	Continuous	COM	Continuous opacity monitoring measurements
FGD for Unit #1	pH	Daily	5.5	Continuous emission monitoring system measurement data. (The FGD liquor flow rate is not measured at the pumps. The gas-side ΔP is not measured; rather, the system is equipped with pressure switches to trip the unit.)
	SO_2 CEMS	Continuous	SO_2 CEMS	
FGD for Unit #2	pH	Daily	5.5	Continuous emission monitoring system measurement data. (The FGD liquor flow rate is not measured at the pumps. The gas-side ΔP is not measured; rather, the system is equipped with pressure switches to trip the unit.)
	SO_2 CEMS	Continuous	SO_2 CEMS	

Test Requirements

(a) PM Testing

Emission units	Control device	When to test	Pollutants	Frequency of testing
Dry bottom, pulverized coal-fired boiler (Unit 1)	fabric filter	Before May 2009	PM	Every two years
Dry bottom, pulverized coal-fired boiler (Unit 2)	Electrostatic precipitator	Before April 2010	PM	Every two years

Recommendation

The staff recommends to the Commissioner that the Part 70 Operating Permit Renewal be approved. This recommendation is based on the following facts and conditions:

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 April 14, 2008.

Conclusion

The operation of this electric utility generating station shall be subject to the conditions of the attached Part 70 Operating Permit Renewal No. T129-26415-00010.

Appendix A: Emissions Calculations
Emission Summary

Source Name: Southern Indiana Gas and Electric Company (SIGECO)
AB. Brown Generating Station
Source Location: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Number: T129-26415-00010
Permit Reviewer: Josiah Balogun
Date: 27-Aug-2008

Uncontrolled Potential Emissions

	PM (tons/yr)	PM_{10} (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	HAPs (tons/yr)
Emission Unit							
Coal-fired boiler Unit # 1	> 100	> 100	> 100	< 100	> 100	> 100	Single HAP > 9 Combined HAPs > 24
Coal-fired boiler Unit # 2	> 100	> 100	> 100	< 100	> 100	> 100	
Lime Storage and handling system			0	0	0	0	0
Soda ash Storage and handling system			0	0	0	0	0
Coal Storage and handling system	> 100	> 100	0	0	0	0	0
Turbine Unit ABB CT # 3	45.2	16.89	198.41	8.25	298.6	942.9	5.3
Turbine Unit ABB # 4	21.9	21.9	17.06	7.45	224.6	133.9	2.9
Auxiliary Boiler Unit # 8	0	0.001	0	0.001	0.012	0.015	neg
Total Emissions	> 100	> 100	> 100	< 100	> 100	> 100	Single HAP > 10 Combined HAPs > 25

Note:
Lime Storage and handling system and Soda ash storage system limited emissions are based on 326 IAC 6-3-2(e)(3) assuming the process weight rate is 200 tons per hour

Coal Storage and handling system limited emissions are based on 326 IAC 6-3-2(e)(3) with process weight rate of 600 tons per hr

Appendix A: Emissions Calculations
Emission Summary

Source Name: Southern Indiana Gas and Electric Company (SIGECO)
AB. Brown Generating Station
Source Location: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Number: T129-26415-00010
Permit Reviewer: Josiah Balogun
Date: 27-Aug-2008

Limited Potential Emissions

	PM (tons/yr)	PM_{10} (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	HAPs (tons/yr)
Emission Unit							
Coal-fired boiler Unit # 1	> 100	> 100	> 100	< 100	> 100	> 100	Single HAP > 10 Combined HAPs > 25
Coal-fired boiler Unit # 2	> 100	> 100	> 100	< 100	> 100	> 100	
Lime Storage and handling system	3.84	3.84	0	0	0	0	0
Soda ash Storage and handling system	3.84	3.84	0	0	0	0	0
Coal Storage and handling system	8.02	8.02	0	0	0	0	0
Turbine Unit ABB CT # 3	9.7	9.7	39.7	2	66	39.9	1.0
Turbine Unit ABB # 4	21.9	21.9	17.06	7.45	224.6	133.9	2.9
Auxiliary Boiler Unit # 8	0	0.001	0.1	0.001	0.012	0.015	neg
Total Emissions	> 100	> 100	> 100	< 100	> 100	> 100	Single HAP >10 Combined HAPs > 25

Appendix A: Emission Calculations
No. 2 Distillate Oil-Fired Turbine
ABB CT Unit No. 3

Source Name: Southern Indiana Gas and Electric Company (SIGECO)
AB. Brown Generating Station
Source Location: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Number: T129-26415-00010
Permit Reviewer: Josiah Balogun
Date: 27-Aug-2008

Heat Input Capacity MMBtu/hr		Fuel Sulfur Content, S %
897.0	No. 2 distillate oil as fuel	0.05

	Criteria Pollutant						
	condensible PM	filterable PM	total PM	SO2	NOx	VOC	CO
Emission Factor, lb/MMBtu, uncontrolled*	7.20E-03	4.30E-03			8.80E-01	4.10E-04	3.30E-03
Emission Factor, lb/MMBtu, with steam injec	7.20E-03	4.30E-03		1.01S	2.40E-01		7.60E-02
Vendor guaranteed emissions in ppm **					42.0000		25.0000
Vendor guaranteed emissions in lb/hr **			10.0 lb/hr		180.0000		61.0000
Potential Emissions in lb/hr, steam injection *	6.4584	3.8571		45.2985	215.2800	0.3678	68.1720
Maximum allowable emissions in lb/hr **			10.0000		180.0000		61.0000
Potential Emissions, tons/yr, uncontrolled*							
Potential Emissions, tons/yr, steam injection*	28.29	16.89		198.41	942.93	1.61	298.59
Potential Emissions, tons/yr, guaranteed **			43.80		788.40		267.18
PTE @ 500 hrs, steam injection, tons/year *	1.61	0.96		11.32	53.82	0.09	17.04
PTE @ 500 hrs, Guaranteed, tons/year **			2.50		45.00		15.25

Hazardous Air Pollutant (HAP)	Emission Factor * (lbs/MMBtu)	Emissions (lbs/hr)	Total Potential Emiss.* (tons/yr)	PTE @ 500 hrs* (tons/yr)
Acetaldehyde	3.03E-05	2.72E-02	0.119	0.007
Benzene	8.30E-05	7.45E-02	0.326	0.019
Cadmium	4.80E-06	4.31E-03	0.019	0.001
Chromium	1.08E-05	9.69E-03	0.042	0.002
Formaldehyde	2.81E-04	2.52E-01	1.104	0.063
Lead	1.42E-05	1.27E-02	0.056	0.003
Manganese	7.89E-04	7.08E-01	3.100	0.177
Mercury	1.20E-06	1.08E-03	0.005	0.000
Nickel	5.20E-05	4.66E-02	0.204	0.012
POM	8.74E-05	7.84E-02	0.343	0.020
TOTAL			**5.32**	**0.30**

Methodology

* From AP-42, Section 3.1 Tables 3.1-1, 3.1-2a, 3.1-3, 3.1-4, and 3.1-5, updated 4/00; and August 21, 2001, Sims Roy memo.
** Provided in application. SO2 emission factor from AP 42, Section #.1, Table 3.4-2, updated 5/98.
Emissions (tons/yr) = Heat input rate (MMBtu/hr) x Emission Factor (lb/MMBtu) * 8760 hr/yr / 2,000 lb/ton
Guaranteed max emissions in tons/yr are guaranteed hourly emissions x 8760 hrs/yr x 1 ton/2000 lbs; except SO2 from AP-42.
Limited Emissions (tons/yr) = Heat input rate (MMBtu/hr) x Emission Factor (lb/MMBtu) * 500 hr/yr / 2,000 lb/ton

Notes: Potential HAPs emissions included for information only.
The AP-42 factors for VOC and some of the HAPs have a "D" or "E" rating, which indicates that they are only expected to provide an order-of-magnitude value.

Appendix A: Emission Calculations
Natural Gas-Fired Turbine, Dry-Low-NOx burners
ABB CT Unit No. 3

Source Name: Southern Indiana Gas and Electric Company (SIGECO)
AB. Brown Generating Station
Source Location: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Number: T129-26415-00010
Permit Reviewer: Josiah Balogun
Date: 27-Aug-2008

Heat Input Capacity
MMBtu/hr
897.0

Sulfur content of fuel (S)
0.0056

	Criteria Pollutant						
	condensible PM	filterable PM	total PM	SO2	NOx	VOC	CO
Emission Factor, lb/MMBtu, lean pre-mix*	0.0047	0.0019	- - - -	0.94S	0.0990	0.0021	0.0150
Vendor guaranteed emissions in ppm**					9.0000		25.0000
Vendor guaranteed emissions in lb/hr **			5.0000		36.0000		60.0000
Potential Emissions, lb/hr, Lean-premix *	4.2159	1.7043		4.7218	88.8030	1.8837	13.4550
Maximum allowable emissions, lb/hr**			5.0000		36.0000		60.0000
Potential Emissions, Lean-premix, tons/yr *	18.47	7.46	- - - -	20.68	388.96	8.25	58.93
Potential Emissions, Guaranteed, tons/yr **			21.90		157.68		262.80
PTE @ 8,260 hrs/yr, Lean-premix, tons/yr **	17.41	7.04	- - - -	19.50	366.76	7.78	55.57
PTE @ 8,260 hrs, Guaranteed, tons/year **			20.65		148.68		247.80

Hazardous Air Pollutant (HAP)	Emission Factor* (lbs/MMBtu)	Emissions (lbs/hr)	Total Potential Emiss. (tons/yr)	PTE @ 8260 hrs (tons/yr)
Acetaldehyde	4.510E-05	4.05E-02	0.177	0.167
Benzene	1.450E-04	1.30E-01	0.570	0.537
Formaldehyde	2.200E-04	1.97E-01	0.864	0.815
POM	4.320E-06	3.88E-03	0.017	0.016
TOTAL			**1.63**	**1.54**

Methodology

Sulfur content is maximum allowable; actual data from gas supplier shows 0.00020 to 0.00035 percent by weight.
* From AP-42, Section 3.1 Tables 3.1-1 (uncontrolled and lean-premix values), 3.1-2a, and 3.1-3, updated 4/00; and August 21, 2001, Sims Roy memo.
** Provided in application. NOx guaranteed at 36 lbs/hr at all times, and at 9ppm or less except during start up & shut down.
Potential Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760 hrs/yr x 1 ton/ 2,000 lbs
Guaranteed max emissions in tons/yr are hourly max emissions x 8760 hrs/yr x 1 ton/2000 lbs.

PM-10 emission factor and guaranteed emissions are total of condensable and filterable emissions.
Worst case annual emissions are guaranteed hourly emissions @ 8,260 hrs/yr of natural gas operation, plus 500 hrs/yr of distillate oil operation. Exception is SO2 which is based on AP-42 emission factors.
*** Speciated PAH not included in HAPs table to avoid double counting of emissions.

Notes: Potential HAPs emissions included for information only.
The AP-42 factors for NOx (lean-premix), CO (lean-premix), VOC, and some of the HAPs have a "D" rating, which indicates that they are only expected to provide an order-of-magnitude value.

Appendix A: Emission Calculations
Natural Gas-Fired Turbine, Dry-Low-NOx burners
ABB CT Unit No.4

Source Name: Southern Indiana Gas and Electric Company (SIGECO)
AB. Brown Generating Station
Source Location: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Number: T129-26415-00010
Permit Reviewer: Josiah Balogun
Date: 27-Aug-2008

Simple Cycle Operation
Combustion Turbine Potential to Emit Calculations - Before Controls or Federally Enforceable Limits

Combustion Turbine Heat input @ 59 F **1145.80** MMBtu/hr Number of Turbines **1**

	Normal Operation	Startup/Shutdown
Hours per year of Operation	**8640**	**120**

Combustion Turbine					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	1145.8 MMBtu/hr	0.0271 lb/MMBtu	31.00	133.92 tons/yr	133.92 tons/yr
CO	1145.8 MMBtu/hr	0.0454 lb/MMBtu	52.00	224.64 tons/yr	224.64 tons/yr
VOC	1145.8 MMBtu/hr	0.0015 lb/MMBtu	1.70	7.45 tons/yr	7.45 tons/yr
SO_2	1145.8 MMBtu/hr	0.0034 lb/MMBtu	3.90	17.06 tons/yr	17.06 tons/yr
PM_{10}	1145.8 MMBtu/hr	0.0044 lb/MMBtu	5.00	21.90 tons/yr	21.90 tons/yr

Emission factors are vendor provided data
Calculations are based on Normal Opeartion + Startup/Shutdown = 8760 hrs/yr

Company Name: Southern Indiana Gas and Electric Company (SIGECO)
AB. Brown Generating Station
Address City IN Zip: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Number: T129-26415-00010
Reviewer: Josiah Balogun
Date: 27-Aug-2008

Combustion Turbine Potential to Emit Calculations for HAPs

Pollutant	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE/Turbine (tpy)	Total PTE (tpy)	Limited Total PTE (tpy)
Benzene	1.20E-05	0.0137	0.060	0.060	0.060
Formaldehyde*	2.92E-04	0.3346	1.465	1.465	1.465
Xylenes	6.40E-05	0.0733	0.321	0.321	0.321
Ethylbenzene	3.20E-05	0.0367	0.161	0.161	0.161
1,3 Butadiene	4.30E-07	0.0005	0.002	0.002	0.002
Napthalene	1.30E-06	0.0015	0.007	0.007	0.007
Toluene	1.30E-04	0.1490	0.652	0.652	0.652
PAH	2.20E-06	0.0025	0.011	0.011	0.011
Acetaldehyde	4.00E-05	0.0458	0.201	0.201	0.201
			single HAP	1.47	1.47
			combined HAP	2.88	2.88

HAPs emission factor are from AP-42 Table 3.1-3

* Formaldehyde emission factor based on Sims Roy memo dated August 21, 2001 of US EPA, OAQPS

Source Name: Southern Indiana Gas and Electric Company (SIGECO)
AB. Brown Generating Station
Source Location: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Number: T129-26415-00010
Permit Reviewer: Josiah Balogun
Date: 27-Aug-2008

Startup/Shutdown Emissions

Simple Cycle Operation

Estimated max number of startups/shutdown for natural gas per year: 240

Natural Gas

Emissions from Simple Cycle Operation				
Pollutant	Startup Emission (lb/startup)	Shutdown Emission (lb/shutdown)	Emission Rate/Turbine (tons/yr)	Total Emission Rate (tons/yr)
NO_X	20.7	11	3.80	3.80
CO	65.5	58.9	14.93	14.93

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
Auxiliary Boiler Unit # 8

Company Name: Southern Indiana Gas and Electric Company (SIGECO)
AB. Brown Generating Station
Address City IN Zip: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Number: T129-26415-00010
Reviewer: Josiah Balogun
Date: 27-Aug-2008

Heat Input Capacity MMBtu/hr	Potential Throughput MMCF/yr
0.0335	0.3

	Pollutant					
	PM*	PM10*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	0.6	100.0 **see below	5.5	84.0
Potential Emission in tons/yr	0.000	0.001	0.000	0.015	0.001	0.012

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology

All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03 (SUPPLEMENT D 3/98)
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
See page 9 for HAPs emissions calculations.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
Auxiliary Boiler Unit # 8
HAPs Emissions

Company Name: Southern Indiana Gas and Electric Company (SIGECO)
AB. Brown Generating Station
Address City IN Zip: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Number: T129-26415-00010
Reviewer: Josiah Balogun
Date: 27-Aug-2008

	HAPs - Organics				
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Potential Emission in tons/yr	3.081E-07	1.761E-07	1.100E-05	2.641E-04	4.989E-07

	HAPs - Metals				
	Lead	Cadmium	Chromium	Manganese	Nickel
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03
Potential Emission in tons/yr	7.337E-08	1.614E-07	2.054E-07	5.576E-08	3.081E-07

Methodology is the same as page 8.

The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.