INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Thomas W. Easterly
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100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
(800) 451-6027
www.IN.gov/idem

TO: Interested Parties / Applicant

DATE: September 26, 2006

RE: PSEG Lawrenceburg Energy Co., LLC / 029-18580-00033

FROM: Nisha Sizemore
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, Room 1049, 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:

(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

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Indianapolis, Indiana 46204-2251
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(800) 451-6027
www.IN.gov/idem

PART 70 OPERATING PERMIT
OFFICE OF AIR QUALITY

PSEG Lawrenceburg Energy Company, LLC
582 West Eads Parkway
Lawrenceburg, Indiana 47025

(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.: T029-18580-00033	
Original signed by: Nisha Sizemore, Chief Permits Branch Office of Air Quality	Issuance Date: September 26, 2006 Expiration Date: September 26, 2011

TABLE OF CONTENTS

SECTION A SOURCE SUMMARY 6
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 Operating Permit Applicability [326 IAC 2-7-2]

SECTION B GENERAL CONDITIONS 8
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 15-13-6(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]
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]
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] [326 IAC 2-2-2] [326 IAC 2-3-2]
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]
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]

SECTION C SOURCE OPERATION CONDITIONS 19

Emission Limitations and Standards [326 IAC 2-7-5(1)]
C.1 Opacity [326 IAC 5-1]
C.2 Open Burning [326 IAC 4-1] [IC 13-17-9]
C.3 Incineration [326 IAC 4-2] [326 IAC 9-1-2]
C.4 Fugitive Dust Emissions [326 IAC 6-4]
C.5 Stack Height [326 IAC 1-7]
C.6 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

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

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

TABLE OF CONTENTS (Continued)

Compliance Monitoring Requirements [326 IAC 2-7-5(1)] [326 IAC 2-7-6(1)]
C.9 Compliance Monitoring [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]
C.10 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]
C.11 Monitoring Methods [326 IAC 3][40 CFR 60]

Corrective Actions and Response Steps [326 IAC 2-7-5] [326 IAC 2-7-6]
C.12 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]
C.13 Risk Management Plan [326 IAC 2-7-5(12)] [40 CFR 68]
C.14 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]
C.15 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5] [326 IAC 2-7-6]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
C.16 Emission Statement [326 IAC 2-7-5(3)(C)(iii)] [326 IAC 2-7-5(7)] [326 IAC 2-7-19(c)] [326 IAC 2-6]
C.17 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6][326 IAC 2-2] [326 IAC 2-3]
C.18 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2] [326 IAC 2-3]

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

SECTION D.1 FACILITY OPERATION CONDITIONS 27

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.1.1 PSD BACT Requirements [326 IAC 2-2-3] [326 IAC 2-1.1-5]
D.1.2 SO_2 Limitations [326 IAC 7-2]
D.1.3 VOC Limitations [326 IAC 8-1-6]

Compliance Determination Requirements
D.1.4 Nitrogen Oxide Control
D.1.5 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11] [326 IAC 2-2]

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]
D.1.6 Continuous Emissions Monitoring [326 IAC 3-5] [326 IAC 2-2][40 CFR 60, Subpart GG]
D.1.7 CO Monitoring System Downtime [326 IAC 2-2] [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.1.8 Record Keeping Requirements
D.1.9 Reporting Requirements

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]
D.1.10 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
D.1.11 New Source Performance Standards for Stationary Gas Turbines Requirements [40 CFR Part 60, Subpart GG] [326 IAC 12]
D.1.12 New Source Performance Standards for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 Requirements [40 CFR Part 60, Subpart Da] [326 IAC 12]

SECTION D.2 FACILITY OPERATION CONDITIONS 49

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.2.1 PSD BACT Requirements [326 IAC 2-2-3]
D.2.2 Startup, Shutdown, and Other Opacity Limits [326 IAC 5-1-3]

TABLE OF CONTENTS (Continued)

Compliance Determination Requirements
D.2.3 Nitrogen Oxide Control
D.2.4 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11] [326 IAC 2-2]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.2.5 Record Keeping Requirements
D.2.6 Reporting Requirements

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]
D.2.7 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
D.2.8 New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units Requirements [40 CFR Part 60, Subpart Db] [326 IAC 12]
D.2.9 One Time Deadlines Relating to New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60, Subpart Db]

SECTION D.3 FACILITY OPERATION CONDITIONS 58

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.3.1 PSD BACT Requirements [326 IAC 2-2-3]
D.3.2 PM Limitations [326 IAC 6.5-1-2]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.3.3 Record Keeping Requirements
D.3.4 Reporting Requirements

SECTION D.4 FACILITY OPERATION CONDITIONS 60

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.4.1 PSD BACT Requirements [326 IAC 2-2-3]

Compliance Determination
D.4.2 Particulate Control

SECTION D.5 FACILITY CONDITIONS 61

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.5.1 PSD BACT Requirements [326 IAC 2-2-3]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.5.2 Record Keeping Requirements
D.5.3 Reporting Requirements

SECTION D.6 FACILITY CONDITIONS 62

Emission Limitations and Standards [326 IAC 2-7-5(1)]
D.6.1 Volatile Organic Compounds (VOC) [326 IAC 8-3-2]
D.6.2 Volatile Organic Compounds (VOC) [326 IAC 8-3-5]

SECTION E TITLE IV CONDITIONS 64

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

TABLE OF CONTENTS (Continued)

SECTION F Nitrogen Oxides Budget Trading Program - NO_x Budget Permit for NO_x Budget Units Under 326 IAC 10-4-1(a) 65

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)]FACILITY CONDITIONS

Certification 69
Emergency Occurrence Report.. 70
Quarterly Report..72-84
Quarterly Deviation and Compliance Monitoring Report 85

Appendix A: Acid Rain Permit

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 a 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 utility generating station.

Responsible Official:	General Manager
Source Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
General Source Phone Number:	(812) 532-2300
SIC Code:	4911
County Location:	Dearborn
Source Location Status:	Nonattainment for PM2.5 and ozone under the 8-hour standard Attainment for all other criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD, Emission Offset, and Nonattainment NSR; Minor 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) Four (4) natural gas-fired combustion turbine generators, identified as units CT1, CT2, CT3, and CT4, commenced construction in 2001, each with a maximum heat input capacity of 1,906.4 MMBtu/hr (higher heating value), equipped with low NOx burners, controlled by four (4) selective catalytic reduction (SCR) systems (SCR11, SCR12, SCR21 and SCR22), and exhausting to stacks S1, S2, S3 and S4, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The combined nominal power output is 1,130 megawatts (MW). Under 40 CFR Part 60, Subpart GG, turbines CT1 through CT4 are considered stationary gas turbines.

(b)* Four (4) heat recovery steam generators, identified as units HRSG1, HRSG2, HRSG3, and HRSG4, commenced construction in 2001, equipped with natural gas fired duct burners, each with a maximum heat input capacity of 310 MMBtu/hr (higher heating value), controlled by four (4) SCR systems (SCR11, SCR12, SCR21 and SCR22), and exhausting to stacks S1, S2, S3, and S4, respectively. Each stack has CEMs for NOx and CO. Under 40 CFR Part 60, Subpart Da, the duct burners are considered steam generating units.

(c) One (1) natural gas fired auxiliary boiler, identified as Auxiliary Boiler, commenced construction in 2001, with a maximum heat input capacity of 114.6 MMBtu/hr, equipped with a low NOx burner, and exhausting to stack S5. Under 40 CFR Part 60, Subpart Db, the auxiliary boiler is considered a steam generating unit.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners which are a source of emissions.

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) Diesel emergency generators not exceeding 1,600 horsepower [326 IAC 2-2-3]:

   (1) One (1) diesel backup electric generator, commenced construction in 2001, with a maximum power output of 1,000 kilowatts (1,342 horsepower), and exhausting to stack S8.

   (2) One (1) diesel fire pump, commenced construction in 2001, with a maximum power output of 265 horsepower (hp), and exhausting to stack S9.

(b) Forced and induced draft cooling tower system not regulated under a NESHAP, including two (2) cooling towers, identified as Cooling Tower 1 and Cooling Tower 2, commenced construction in 2001, each equipped with a high efficiency drift eliminator for PM control, and exhausting to stacks S6 and S7, respectively. [326 IAC 2-2-3] [326 IAC 6.5-1-2]

(c) Natural gas-fired combustion sources with heat input equal to or less than ten million (10,000,000) Btu per hour, including one (1) startup gas heater, identified as GH1, commenced construction in 2003, with a maximum heat input capacity of 2.4 MMBtu/hr, and exhausting to stack GH1. [326 IAC 2-2-3]

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

(e) Paved and unpaved roads and parking lots with public access [326 IAC 6-4].

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

This stationary source is required to have a Part 70 operating 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 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 15-13-6(a)]

(a) This permit, T029-18580-00033, 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 a 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. The initial certification shall cover the time period from the date of final permit issuance through December 31 of the same year. All subsequent certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted in letter form no later than July 1 of each year to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue
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 Section 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 prepare and maintain Preventive Maintenance Plans (PMPs) within ninety (90) days after issuance of this permit, for the sources as described in 326 IAC 1-6-3. At a minimum, the PMP shall include:

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

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

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

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

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

The PMP extension notification does not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(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. IDEM, OAQ, may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions or potential to emit. 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, 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

(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
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 PMP 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 in 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 operating 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 operating 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]

(a) All terms and conditions of permits established prior to T029-18580-00033 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.

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
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
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 operating 70 permit amendments and permit modifications for purposes of the acid rain portion of a Part 70 operating 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
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 operating permit revision shall be required under any approved economic incentives, marketable Part 70 operating permits, emissions trading, and other similar programs or processes for changes that are provided for in a Part 70 operating permit.

(b) Notwithstanding 326 IAC 2-7-12(b)(1) and 326 IAC 2-7-12(c)(1), minor Part 70 operating permit modification procedures may be used for Part 70 modifications involving the use of economic incentives, marketable Part 70 operating permits, emissions trading, and other similar approaches to the extent that such minor Part 70 operating 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
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 which document, on a rolling five (5) year basis, which document all such changes and emissions 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] [326 IAC 2-2-2] [326 IAC 2-3-2]

(a) The Permittee shall obtain approval as required by 326 IAC 2-7-10.5 from the IDEM, OAQ prior to making any modification to the source. Pursuant to 326 IAC 1-2-42, "Modification" means one (1) or more of the following activities at an existing source:

(1) A physical change or change in the method of operation of any existing emissions unit that increases the potential to emit any regulated pollutant that could be emitted from the emissions unit, or that results in emissions of any regulated pollutant not previously emitted.

(2) Construction of one (1) or more new emissions units that have the potential to emit regulated air pollutants.

(3) Reconstruction of one (1) or more existing emission units that increases the potential to emit of any regulated air pollutant.

(b) Any application requesting a source modification shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

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

(c) The Permittee shall also comply with the applicable provisions of 326 IAC 2-7-11 (Administrative Permit Amendments) or 326 IAC 2-7-12 (Permit Modification) prior to operating the approved modification.

(d) Any modification at an existing major source is governed by the requirements of 326 IAC 2-2-2 and 326 IAC 2-3-2.

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
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 bill. 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 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 thirty percent (30%) 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.2 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. 326 IAC 4-1-3 (a)(2)(A) and (B) are not federally enforceable.

C.3 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. 326 IAC 9-1-2 is not federally enforceable.

C.4 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.5 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.

C.6 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

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

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

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

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

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

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

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

All required notifications shall be submitted to:

Indiana Department of Environmental Management
Asbestos Section, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

(g) Indiana Accredited Asbestos Inspector
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Accredited Asbestos Inspector to thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Accredited Asbestos inspector is not federally enforceable.

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

C.7 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
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.8 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.9 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
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.10 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) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 40 CFR 60, Subpart Da.

C.11 Monitoring Methods [326 IAC 3] [40 CFR 60]

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, or other approved methods as specified in this permit.

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

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

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

(a) The Permittee prepared and submitted written emergency reduction plans (ERPs) consistent with safe operating procedures on March 16, 2004.

(b) Upon direct notification by IDEM, OAQ, that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level.
[326 IAC 1-5-3]

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

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

C.14 Response to Excursions or Exceedances [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(s) (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

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

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall 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 and 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.16 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

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

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. 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 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 Clean Unit (or at a source with Plant-wide 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) 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)(iii); and

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

(2) 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

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

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

(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
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) The first report shall cover the period commencing on the date of issuance of this permit and ending on the last day of the reporting period. 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 Electric Utility Steam Generating Unit, then for that project the Permittee shall:

(1) Submit to IDEM, OAQ a copy of the information required by (c)(1) in Section C- General Record Keeping Requirements

(2) Submit a report to IDEM, OAQ within sixty (60) days after the end of each year during which records are generated in accordance with (c)(2) and (3) in Section C- General Record Keeping Requirements. The report shall contain all information and data describing the annual emissions for the emissions units during the calendar year that preceded the submission of 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
Indianapolis, Indiana 46204-2251

(g) 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 other than Electric Utility Steam Generating 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).

(h) The report for project at an existing emissions unit other than Electric Utility Steam Generating 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
Indianapolis, Indiana 46204-2251

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

Stratospheric Ozone Protection

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

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

SECTION D.1 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(a) Four (4) natural gas-fired combustion turbine generators, identified as units CT1, CT2, CT3, and CT4, commenced construction in 2001, each with a maximum heat input capacity of 1,906.4 MMBtu/hr (higher heating value), equipped with low NOx burners, controlled by four (4) selective catalytic reduction (SCR) systems (SCR11, SCR12, SCR21 and SCR22), and exhausting to stacks S1, S2, S3 and S4, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The combined nominal power output is 1,130 megawatts (MW). Under 40 CFR Part 60, Subpart GG, turbines CT1 through CT4 are considered stationary gas turbines.

(b)* Four (4) heat recovery steam generators, identified as units HRSG1, HRSG2, HRSG3, and HRSG4, commenced construction in 2001, equipped with natural gas fired duct burners, each with a maximum heat input capacity of 310 MMBtu/hr (higher heating value), controlled by four (4) SCR systems (SCR11, SCR12, SCR21 and SCR22), and exhausting to stacks S1, S2, S3, and S4, respectively. Each stack has CEMs for NOx and CO. Under 40 CFR Part 60, Subpart Da, the duct burners are considered steam generating units.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners which are a source of emissions.

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

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

D.1.1 PSD BACT Requirements [326 IAC 2-2-3] [326 IAC 2-1.1-5]

Pursuant to CP #029-12517-00033, originally issued on June 7, 2001, 326 IAC 2-2-3 (PSD BACT), and 326 IAC 2-1.1-5 (Air Quality Requirements), the Permittee shall comply with the following requirements:

(a) Emissions from each of the combustion turbines CT1, CT2, CT3, and CT4 shall comply with the following emission limits during normal combined cycle operation (50% load or more):

Pollutant	PM/PM10	NOx	CO	SO_2	VOC	Ammonia
Duct Burner is not in Operation	21.0 lbs/hr	21.0 lbs/hr; 3 ppmvd @ 15% O_2 and 3 hour avg.	21.3 lbs/hr; 6 ppmvd @ 15% O_2 and 24 hour avg.	11.0 lbs/hr	3.0 lbs/hr	10 ppmvd @ 15% O_2 and 3 hour block avg.
Duct Burner is in Operation	24.1 lbs/hr	24.41 lbs/hr; 3 ppmvd @ 15% O_2 and 3 hour avg.	40.5 lbs/hr; 9 ppmvd @ 15% O_2 and 24 hour avg.	12.71 lbs/hr	7.7 lbs/hr	10 ppmvd @ 15% O_2 and 3 hour block avg.

(b) The NOx emissions from each of the turbines and the associated burners, excluding startup and shutdown periods, shall not exceed 78.1 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) The CO emissions from each of the turbines and the associated burners, excluding startup and shutdown periods, shall not exceed 102.21 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(d) Each combustion turbine shall be equipped with dry low-NOx burners.

(e) A selective catalytic reduction (SCR) system shall be installed and operated at all times, except during periods of startup and shutdown.

(f) The Permittee shall use natural gas only for these units.

(g) The sulfur content of the natural gas shall not exceed two (2) grains per 100 standard cubic feet (scf).

(h) The duct burners shall not be operated until the associated combustion turbine reaches normal operation.

(i) The Permittee shall use good combustion practices.

(j) Each combustion turbine generating unit shall comply with the following startup and shutdown limitations. A startup or shutdown is defined as less than fifty (50) percent load.

(1) A startup or shutdown period shall not exceed 3.5 hours. The startup and shutdown period for all combustion turbines shall not exceed a total of 2,240 turbine hours per twelve (12) consecutive month period with compliance determined at the end of each month.

(2) During periods of startup and shutdown, good combustion practices shall be used to limit NOx and CO emissions.

(3) The NOx and CO emissions during startup and shutdown periods shall be monitored.

(4) The startup and shutdown data for the first thirty-six (36) months of actual operation shall be submitted to the OAQ Permits Branch in order to evaluate and establish a short-term limit (pounds per startup and pounds per shutdown) during periods of startup and shutdown. The short-term limit shall consider, but will not be limited to, performance degradation of the combustion turbine up to the first major overhaul. The startup and shutdown data shall be submitted within 90 days after the 36-month monitoring period.

D.1.2 SO_2 Limitations [326 IAC 7-2]

The SO_2 emissions from the combustion turbines (CT1 through CT4) are subject to the requirements of 326 IAC 7(Sulfur Dioxide Emission Limitations). Pursuant to 326 IAC 7-2-1(c)(3), the Permittee shall submit reports of the calendar month average sulfur content, heat content, natural fuel consumption and SO_2 emission rate in pounds per MMBtu, upon request of IDEM, OAQ.

D.1.3 VOC Limitations [326 IAC 8-1-6]

The VOC emissions from the combustion turbines (CT1 through CT4) are subject to the requirements of 326 IAC 8-1-6 (BACT). Pursuant to CP #029-12517-00033, originally issued on June 7, 2001, compliance with the PSD BACT requirements in Condition D.1.1(a) satisfied the requirements of 326 IAC 8-1-6.

Compliance Determination Requirements

D.1.4 Nitrogen Oxide Control

Pursuant to CP #029-12517-00033, originally issued on June 7, 2001 and in order to comply with Condition D.1.1, the SCR systems and low NOx burners for NOx control shall be in operation and control emissions from stacks S1 through S4 at all times that the associated facilities are in operation (except during periods of startup and shutdown).

D.1.5 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11] [326 IAC 2-2]

In order to demonstrate compliance with Conditions D.1.1(a), no later than five (5) years from the date of the last valid compliance demonstration, the Permittee shall perform PM and PM10 testing for each of the combustion turbines CT1 through CT4 (stacks S1 through S4), utilizing methods as approved by the Commissioner. Testing shall be conducted with and without the duct burners in operation. This test shall be repeated once every five (5) years from the date of the last valid compliance demonstration. PM10 includes filterable PM10 and condensable PM10. Testing shall be conducted in accordance with Section C - Performance Testing.

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

D.1.6 Continuous Emissions Monitoring [326 IAC 3-5] [326 IAC 2-2]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) and 326 IAC 2-2 (PSD), the Permittee is required to calibrate, certify, operate and maintain a continuous emission monitoring system (CEMS) for measuring NOx, CO, and O_2 emissions rates from the combustion turbine stacks (stacks S1 through S4) in accordance with 326 IAC 3-5 to demonstrate compliance with Condition D.1.1(a).

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

(c) Pursuant to 326 IAC 3-5-4(a), if revisions are made to the continuous monitoring standard operating procedures (SOP), the Permittee shall submit updates to the department biennially.

(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.

D.1.7 CO Monitoring System Downtime [326 IAC 2-2] [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

In instances of CO continuous emission monitoring system (CEMS) downtime, the Permittee shall use a data substitution procedure for CO that is consistent with the requirements of 40 CFR Part 75, Appendix D (Optional SO_2 Emissions Data Protocol) for fuel flow meters requirements, and 40 CFR Part 75, Appendix E (Optional NOx Emissions Estimation Protocol) for emission rate curve establishment. CO mass emissions reported shall be based on the fuel-and-unit-specific CO emission rates ("load curve") established during the latest stack test.

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

D.1.8 Record Keeping Requirements

(a) To document compliance with Condition D.1.1(a), the Permittee shall maintain records of the emission rates of NOx and CO in pounds per hour.

(b) To document compliance with Conditions D.1.1(b) and D.1.1(c), the Permittee shall maintain the monthly records of the CO and NOx emissions from each of combustion turbines CT1 through CT4 based the CEM data.

(c) To document compliance with Condition D.1.1(g), the Permittee shall maintain the records of sulfur content of the natural gas combusted in the turbines and the associated duct burners.

(d) To document compliance with Condition D.1.1(j), 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 averaging period per turbine.

(3) The CEMS data, fuel flow meter data, and Method 19 calculations corresponding to each startup and shutdown period.

(e) To document compliance with Condition D.1.6, 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 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.1.9 Reporting Requirements

A quarterly summary of the information to document compliance with Conditions D.1.1(b), D.1.1(c), and D.1.1(j)(1) 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).

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

D.1.10 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the four (4) natural gas combustion turbines CT1 through CT4 and four (4) duct burners associated with the heat recovery steam generators HRSG1 through HRSG4, except as otherwise specified in 40 CFR Part 60, Subparts GG and 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,
Indianapolis, Indiana 46204-2251

D.1.11 New Source Performance Standards for Stationary Gas Turbines Requirements [40 CFR Part 60, Subpart GG] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart GG, the Permittee shall comply with the provisions of New Source Performance Standards for Stationary Gas Turbines, which are incorporated by reference as 326 IAC 12, for the four (4) natural gas combustion turbines CT1 through CT4 as specified as follows:

§ 60.330 Applicability and designation of affected facility

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.

§ 60.331 Definitions.

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

(a) *Stationary gas turbine* means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) *Simple cycle gas turbine* means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) *Regenerative cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) *Combined cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) *Emergency gas turbine* means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) *Ice fog* means an atmospheric suspension of highly reflective ice crystals.

(g) *ISO standard day conditions* means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) *Efficiency* means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) *Peak load* means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) *Base load* means the load level at which a gas turbine is normally operated.

(k) *Fire-fighting turbine* means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) *Turbines employed in oil/gas production or oil/gas transportation* means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A *Metropolitan Statistical Area* or *MSA* as defined by the Department of Commerce.

(n) *Offshore platform gas turbines* means any stationary gas turbine located on a platform in an ocean.

(o) *Garrison facility* means any permanent military installation.

(p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, 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_X emissions are higher than the applicable emission limit in §60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.333; or

(3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

(u) *Natural gas* means a naturally occurring fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

(v) *Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

(w) *Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) *Diffusion flame stationary combustion turbine* means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) *Unit operating day* means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may

choose to apply a NO_X allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(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.

§ 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).

§ 60.334 Monitoring of operations.

(b) (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_2 basis for oxygen; or

(ii) On a ppm at 15 percent O_2 basis; or

(iii) On a ppm basis (for NO_X) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NO_X data 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_X emissions in the units of the applicable NO_X emission 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_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (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_X CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_X emissions, the owner or operator may, 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 or local permitting authority approval of a petition for an alternative procedure of continuously monitoring compliance with the applicable NO_X emission limit under §60.332, that approved procedure may continue to be used, even if it deviates from paragraph (a) of this section.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(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.

(j) For each affected unit required 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.

(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_X concentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a “4-hour rolling average NO_X concentration” is the arithmetic average of the average NO_X concentration 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_X concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_X concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(5) All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter.

§ 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_X concentrations, 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_X concentration during the stratification test; or

(B) If each of the individual traverse point NO_X concentrations, 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_2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$NO_X=(NO_{Xo})(P_r/P_o)^{0.5}\ e19\ (Ho-0.00633)\ (288°K/T_a)^{1.53}$$

Where:

NO_X = emission concentration of NO_X at 15 percent O_2 and ISO standard ambient conditions, ppm by volume, dry basis,

NO_{Xo} = mean observed NO_X concentration, 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_X emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_X emission limit in §60.332 for the combustion turbine must still be met.

(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.

(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.

D.1.12 New Source Performance Standards for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 Requirements [40 CFR Part 60, Subpart Da] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart Da, the Permittee shall comply with the provisions of New Source Performance Standards for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, which are incorporated by reference as 326 IAC 12, for the four (4) duct burners associated with the heat recovery steam generators HRSG1 through HRSG4 as specified as follows:

§ 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 (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

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

§ 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' (ASTM) Standard Specification for Classification of Coals by Rank D388–77 (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.

Bituminous coal means coal that is classified as bituminous according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004)ϵ [1] (incorporated by reference, see §60.17).

Boiler operating day means a 24-hour period during which fossil fuel is combusted in a steam generating unit for the entire 24 hours.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004)ϵ [1] (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other supplemental fuels in any amount. Examples of supplemental fuels include, but are not limited to, petroleum coke and tire-derived fuels.

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

Cogeneration means a facility that simultaneously produces both electrical (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 from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline 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 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 fossil fuel-fired combustion unit of more than 25 megawatts electric (MW) that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MW output to any utility power distribution system for sale is also considered an electric utility steam generating unit.

Electrostatic precipitator or *ESP* means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

Emergency condition means that period of time when:

(a) 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:

(1) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(2) All available purchase power interconnected with the affected facility is being obtained, or

(b) 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

(c) 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 (a) 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 40 CFR 51.18 and 40 CFR 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, and coke-oven gas.

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus one half the useful thermal 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* 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.

Lignite means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, or 98a (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 (ASTM) Standard Specification for Liquid Petroleum Gases D1835–87, 91, 97, or 03a (incorporated by reference, see §60.17).

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 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.

Potential combustion concentration means the theoretical emissions (ng/J, lb/million Btu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems) and:

(a) For particulate matter is:

(1) 3,000 ng/J (7.0 lb/million Btu) heat input for solid fuel; and

(2) 73 ng/J (0.17 lb/million Btu) heat input for liquid fuels.

(b) For sulfur dioxide is determined under §60.48a(b).

(c) For nitrogen oxides is:

(1) 290 ng/J (0.67 lb/million Btu) heat input for gaseous fuels;

(2) 310 ng/J (0.72 lb/million Btu) heat input for liquid fuels; and

(3) 990 ng/J (2.30 lb/million Btu) heat input for solid fuels.

Potential electrical output capacity is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100–MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33–MW 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, and gasified coal.

Spare flue gas desulfurization system module means a separate system of sulfur dioxide emission 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 (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, or 98a (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 sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet FGD technology include, but are not limited to, lime, limestone, and sodium.

§ 60.42Da Standard for particulate matter.

(a) On and after the date on which the 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 any gases which contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(b) On and after the date the particulate matter 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 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.

§ 60.43Da Standard for sulfur dioxide.

(b) 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 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), any gases which contain sulfur dioxide in excess of:

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(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.

§ 60.44Da Standard for nitrogen oxides.

(d)(1) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no new source 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 commenced after July 9, 1997 any gases which contain nitrogen oxides (expressed as NO_2) in excess of 200 nanograms per joule (1.6 pounds per megawatt-hour) gross energy output, based on a 30-day rolling average, except as provided under §60.48Da(k)(1).

§ 60.48Da Compliance provisions.

(a) Compliance with the particulate matter emission limitation under §60.42Da(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under §60.42Da(a)(2) and (3).

(c) The particulate matter emission standards under §60.42Da, the nitrogen oxides emission standards under §60.44Da, and the Hg emission standards under §60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(e) After the initial performance test required under §60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under §60.43Da and the nitrogen oxides emission 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 sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under §60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under §60.43Da and the nitrogen oxides emission limitation under §60.44Da is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide 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) Compliance 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_X only), or emergency conditions (SO_2 only). Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under §60.49Da of this subpart, compliance of the affected facility with the emission requirements under §§60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19.

(i) *Compliance provisions for sources subject to §60.44Da(d)(1).* The owner or operator of an affected facility subject to §60.44Da(d)(1) (new source constructed after July 7, 1997) shall calculate NO_X emissions by multiplying the average hourly NO_X output concentration, measured according to the provisions of §60.49Da(c), 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).

(j) *Compliance provisions for duct burners subject to §60.44Da(a)(1).* To determine compliance with the emissions limits for NO_X required by §60.44a(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:

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the continuous emission monitoring system specified under §60.49Da for measuring NO_X and oxygen and meet the requirements of §60.49a. Data from a CEMS certified (or recertified) according to the provisions of 40 CFR 75.20, meeting the QA and QC requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used. The sampling site shall be located at the outlet from the steam generating unit. The NO_X emission rate at the outlet from the steam generating unit shall constitute the NO_X emission rate from the duct burner of the combined cycle system.

(k) *Compliance provisions for duct burners subject to §60.44Da(d)(1).* To determine compliance with the emissions limits for NO_X required by §60.44Da(d)(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 NO_X standard in §60.44Da(d)(1) as follows:

(i) The emission rate (E) of NO_X shall be computed using Equation 1 of this section:

$E = [(Csg \times Qsg)-(Cte \times Qte)]/(Osg \times h)$ (Eq. 1)

Where:

E = emission rate of NO_X from the duct burner, ng/J (lb/Mwh) gross output

Csg = average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf)

Cte = average hourly concentration of NO_X in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)

Qsg = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

Qte = average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)

Osg = average hourly gross energy output from steam generating unit, J (Mwh)

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_X concentrations (Csg and Cte). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates (Qsg and Qte) 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 emissions limits under §60.44Da (d)(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 NO_X standard in §60.44Da(d)(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_X shall be computed using Equation 2 of this section:

$E = (Csg \times Qsd) / Occ$ (Eq. 2)

Where:

E = emission rate of NO_X from the duct burner, ng/J (lb/Mwh) gross output

Csg = average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf)

Qsg = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh)

(ii) The continuous emissions monitoring system specified under §60.49Da for measuring NO_X and oxygen shall be used to determine the average hourly NO_X concentrations (Csg). The continuous flow monitoring system specified in §60.49Da(l) shall be used to determine the volumetric flow rate (Qsg) of the exhaust gas. The sampling site shall be located at the outlet from the steam generating unit. Data from a continuous flow monitoring system certified (or recertified) following procedures specified in 40 CFR 75.20, meeting the quality assurance and quality control requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used.

(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 (Occ), 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_X emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of 40 CFR part 75. If this compliance option is selected, the emission rate (E) of NO_X shall be computed using Equation 3 of this section:

$E = (ERsg \times Hcc) / Occ$ (Eq. 3)

Where:

E = emission rate of NO_X from the duct burner, ng/J (lb/Mwh) gross output

ERsg = average hourly emission rate of NO_X exiting the steam generating unit heat input calculated using appropriate F-factor as described in Method 19, ng/J (lb/million Btu)

Hcc = average hourly heat input rate of entire combined cycle unit, J/hr (million Btu/hr)

Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh)

§ 60.49Da Emission monitoring.

(c)(2) If the owner or operator has installed a nitrogen oxides emission rate continuous emission monitoring system (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 §60.51a 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 continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The continuous monitoring systems 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 continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f) 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 a continuous monitoring system, 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/million Btu) 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(b). At least two data points must be used to calculate the 1-hour averages.

(h) When it becomes necessary to supplement continuous monitoring system 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 shall be used to determine the SO_2 concentration at the same location as the SO_2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 shall be used to determine the NO_X concentration at the same location as the NO_X monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O_2 or CO_2 concentration at the same location as the O_2 or CO_2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (1b/million Btu) 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 shall be used to determine O_2, SO_2, and NO_X concentrations, respectively.

(2) SO_2 or 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 continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Gas..	500

where:

x is the fraction of total heat input derived from gaseous fossil fuel,

y is the fraction of total heat input derived from liquid fossil fuel, and

z is the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

(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, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under paragraph (i) of this section, the conditions under §60.46(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.

(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(4) For Method 3B, Method 3A 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 megawatt-hour 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 50 percent of the gross thermal output 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 the output-based standard under §60.44Da(d)(1) shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B and procedure 1 of appendix F of this subpart, and record the output of the system, for measuring the flow of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23, may be used.

(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 40 CFR part 75.

(o) The owner or operator of a duct burner, as described in §60.41Da, which is subject to the NO_X standards of §60.44Da(a)(1) or (d)(1) is not required to install or operate a continuous emissions monitoring system to measure NO_X emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

(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 record keeping and reporting procedures in accordance with the requirements of this subpart.

§ 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 particulate matter standards in §60.42Da as follows:

(1) The dry basis F factor (O_2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

(2) For the particular matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B 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 shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentrations at all traverse points.

(3) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO_2 standards in §60.43Da as follows:

(1) The percent of potential SO_2 emissions ($\%P_s$) to the atmosphere shall be computed using the following equation:

$\%P_s=[(100—\%R_f)\ (100—\%R_g)]/100$

where:

$\%P_s$=percent of potential SO_2 emissions, percent.

$\%R_f$=percent reduction from fuel pretreatment, percent.

$\%R_g$=percent reduction by SO_2 control system, percent.

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring system in §60.49Da (b) and (d) shall be used to determine the concentrations of SO_2 and CO_2 or O_2.

(d) The owner or operator shall determine compliance with the NO_X standard in §60.44Da as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NO_X.

(2) The continous monitoring system in §60.49Da (c) and (d) shall be used to determine the concentrations of NO_X and CO_2 or O_2.

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

(1) For Method 5 or 5B, Method 17 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 may be used in Method 17 only if it is used after wet FGD

systems. Method 17 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 may be used to compute the emission rate of particulate matter under the stipulations of §60.48(d)(1). The CO_2 shall be determined in the same manner as the O_2 concentration.

(f) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.51Da Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, particulate matter, 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 sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) 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.

(4) Identification of the boiler operating days for which pollutant or dilutent data have not been obtained by an approved method for at least 18 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_X only), emergency conditions (SO_2 only), 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 continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system 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 (n_o) 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.

(f) For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system 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.

SECTION D.2 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

(c) One (1) natural gas fired auxiliary boiler, identified as Auxiliary Boiler, commenced construction in 2001, with a maximum heat input capacity of 114.6 MMBtu/hr, equipped with a low NOx burner, and exhausting to stack S5. Under 40 CFR Part 60, Subpart Db, the auxiliary boiler is considered a steam generating unit.

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

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

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

Pursuant to CP #029-12517-00033, originally issued on June 7, 2001, and 326 IAC 2-2-3 (PSD BACT), the Permittee shall comply with the following requirements for the Auxiliary Boiler:

(a) Emissions from the Auxiliary Boiler shall not exceed the following emission limits:

Pollutant	Emission Limit (lbs/MMBtu)
PM/PM10	0.0081
NOx	0.036
CO	0.082
SO_2	0.006
VOC	0.0054

(b) The natural gas usage in the Auxiliary Boiler shall not exceed 122.2 Million Standard Cubic Feet (MMSCF) per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) The Permittee shall operate the Auxiliary Boiler with low-NOx burners.

(d) The Permittee shall use natural gas only for the Auxiliary Boiler.

(e) The sulfur content of the natural gas used shall not exceed 0.8% by weight.

(f) The Permittee shall perform good combustion practices for the Auxiliary Boiler.

D.2.2 Startup, Shutdown and Other Opacity Limits [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3 (a) (Temporary Alternative Opacity Limitations), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed the applicable opacity limit 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 opacity 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.

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

Compliance Determination Requirements

D.2.3 Nitrogen Oxide Control

In order to ensure compliance with Condition D.2.1, the low NOx burner shall be in operation and control emissions from the auxiliary boiler at all times that this boiler is in operation.

D.2.4 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11] [326 IAC 2-2]

In order to demonstrate compliance with Condition D.2.1, no later than five (5) years from the date of last valid compliance demonstration, the Permittee shall perform NOx testing for the auxiliary boiler, utilizing methods as approved by the Commissioner. This test shall be repeated once every five (5) years from the date of the last valid compliance demonstration. Testing shall be conducted in accordance with Section C - Performance Testing.

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

D.2.5 Record Keeping Requirements

(a) To document compliance with Condition D.2.1(b), the Permittee shall maintain monthly records of the amount of natural gas combusted for the auxiliary boiler.

(b) To document compliance with Condition D.2.1(e), the Permittee shall maintain records of the sulfur content of natural gas combusted for the auxiliary boiler.

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

D.2.6 Reporting Requirements

A quarterly summary of the information to document compliance with Condition D.2.1(b) 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).

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

D.2.7 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the natural gas fired auxiliary boiler, except as otherwise specified in 40 CFR Part 60, Subpart Db.

(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,
Indianapolis, Indiana 46204-2251

D.2.8 New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units Requirements [40 CFR Part 60, Subpart Db] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart Db, the Permittee shall comply with the provisions of New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units, which are incorporated by reference as 326 IAC 12, for the natural gas fired auxiliary boiler as specified as follows:

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 million Btu/hour).

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to Subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

§ 60.41b 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.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants means industrial plants which are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388–77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (IBR—see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a heat recovery steam generating unit.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396–78, 89, 90, 92, 96, or 98, Standard Specifications for Fuel Oils (incorporated by reference—see §60.17).

Dry flue gas desulfurization technology means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a 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 flue gas desulfurization 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.

Emerging technology means any sulfur dioxide control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

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 40 CFR 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hour) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3).

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388–77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (IBR—see §60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

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 for Testing and Materials in ASTM D1835–82, 86, 87, 91, or 97, “Standard Specification for Liquid Petroleum Gases” (IBR—see §60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical sulfur dioxide emissions (ng/J, lb/million Btu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulp and paper mills means industrial plants which are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units.

Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396–78, Standard Specifications for Fuel Oils (IBR—see §60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste to produce steam or to heat water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating 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 steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Very low sulfur oil means an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 215 ng/J (0.5 lb/million Btu) heat input.

Wet flue gas desulfurization technology means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas 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 flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter or sulfur dioxide.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

§ 60.44b Standard for nitrogen oxides.

(h) For purposes of paragraph (i) of this section, the nitrogen oxide standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(l) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility which commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the following limits:

(1) If the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels: A limit of 86 ng/JI (0.20 lb/million Btu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(c) Compliance with the nitrogen oxides emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(e) To determine compliance with the emission limits for nitrogen oxides required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring nitrogen oxides under §60.48(b).

(1) For the initial compliance test, nitrogen oxides from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the nitrogen oxides emission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(4) Following the date on which the initial performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, the owner or operator of an affected facility which has a heat input capacity of 73 MW (250 million Btu/hour) or less and which combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the nitrogen oxides standards under §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, nitrogen oxides emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the nitrogen oxides emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(c) The continuous monitoring systems required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average nitrogen oxides emission rates measured by the continuous nitrogen oxides monitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/million Btu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(b). At least 2 data points must be used to calculate each 1-hour average.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for nitrogen oxides is determined as follows:

Fuel	Span values for nitrogen oxides PPM)
Natural gas..	500

(f) When nitrogen oxides emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7, Method 7A, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility,

(b) The owner or operator of each affected facility subject to the sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the nitrogen oxides standard of §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions under the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under §60.48b(g)(2) and the records to be maintained under §60.49b(j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and nitrogen oxides emission rates (i.e., ng/J or lbs/million Btu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (i.e., the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e., flue gas oxygen level);

(2) Include the data and information that the owner or operator used to identify the relationship between nitrogen oxides emission rates and these operating conditions;

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(j).

If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan.

(d) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the nitrogen oxides standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date.

(2) The average hourly nitrogen oxides emission rates (expressed as NO_2) (ng/J or lb/million Btu heat input) measured or predicted.

(3) The 30-day average nitrogen oxides emission rates (ng/J or lb/million Btu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days.

(4) Identification of the steam generating unit operating days when the calculated 30-day average nitrogen oxides emission rates are in excess of the nitrogen oxides emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken.

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specification 2 or 3.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h) (1) or (2) of this section is required to submit excess emission reports for any excess emissions which occurred during the reporting period.

(2) Any affected facility that is subject to the nitrogen oxides standard of §60.44b, and that

(i) Combusts natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 weight percent or less, or

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for nitrogen oxides under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) 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.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

D.2.9 One Time Deadlines Relating to New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60, Subpart Db]

The Permittee must conduct the initial performance tests within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup of the Auxiliary Boiler.

SECTION D.3 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] - Insignificant Activities

(a) Diesel emergency generators not exceeding 1,600 horsepower [326 IAC 2-2-3]:

(1) One (1) diesel backup electric generator, commenced construction in 2001, with a maximum power output of 1,000 kilowatts (1,342 horsepower), and exhausting to stack S8.

(2) One (1) diesel fire pump, commenced construction in 2001, with a maximum power output of 265 horsepower (hp), and exhausting to stack S9.

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

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

D.3.1 PSD BACT Requirements [326 IAC 2-2-3]

Pursuant to CP #029-12517-00033, originally issued on June 7, 2001, and 326 IAC 2-2-3 (PSD BACT), the Permittee shall comply with the following requirements for the diesel backup electric generator and the diesel fired pump:

(a) The total fuel input to the diesel backup electric generator shall not exceed 35,252 gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

(b) The total fuel input to the diesel fire pump shall not exceed 7,554 gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) The sulfur content of the diesel fuel used shall not exceed 0.05% by weight.

(d) The Permittee shall perform good combustion practice for these units.

D.3.2 PM Limitations [326 IAC 6.5-1-2]

Pursuant to 326 IAC 6.5-1-2(a) (formerly 326 IAC 6-1-2(a)), particulate matter (PM) from each of the emergency generators shall not exceed 0.03 grain per dry standard cubic foot (gr/dscf) of exhaust air.

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

D.3.3 Record Keeping Requirements

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

(1) Amount of diesel fuel combusted each month in the diesel backup electric generator.

(2) Amount of diesel fuel combusted each month in the diesel fire pump.

(3) The percent sulfur content of the diesel fuel used.

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

D.3.4 Reporting Requirements

A quarterly summary of the information to document compliance with Conditions D.3.1(a) and D.3.1(b) 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).

SECTION D.4 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] - Insignificant Activities

(b) Forced and induced draft cooling tower system not regulated under a NESHAP, including two (2) cooling towers, identified as Cooling Tower 1 and Cooling Tower 2, commenced construction in 2001, each equipped with a high efficiency drift eliminator for PM control, and exhausting to stacks S6 and S7, respectively. [326 IAC 2-2-3] [326 IAC 6.5-1-2]

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

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

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

Pursuant to CP #029-12517-00033, originally issued on June 7, 2001, and 326 IAC 2-2-3 (PSD BACT), the Permittee shall comply with the following requirements for each of the cooling towers:

(a) The total PM and PM10 emissions shall not exceed 0.876 lbs/hr for each cooling tower.

(b) The Permittee shall use good design and operation practices to limit the emissions from each cooling tower.

Compliance Determination

D.4.2 Particulate Control

In order to comply with Condition D.4.1(a), the high efficiency drift eliminators for particulate control shall be in operation and control emissions from the cooling towers at all times that the facilities are in operation.

SECTION D.5 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] - Insignificant Activities

(c) Natural gas-fired combustion sources with heat input equal to or less than ten million (10,000,000) Btu per hour, including one (1) startup gas heater, identified as GH1, commenced construction in 2003, with a maximum heat input capacity of 2.4 MMBtu/hr, and exhausting to stack GH1. [326 IAC 2-2-3]

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

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

D.5.1 PSD BACT Requirements [326 IAC 2-2-3]

Pursuant to Significant Modification #029-16235-00033, issued on December 23, 2002, and 326 IAC 2-2-3 (PSD BACT), the Permittee shall comply with the following requirements for the startup heater GH1:

(a) The NOx emissions shall not exceed 0.14 lbs/MMBtu.

(b) The natural gas usage shall not exceed 5.3 Million Standard Cubic Feet (MMSCF) per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) Natural gas shall be the only fuel combusted by the gas heater GH1.

(d) The Permittee shall use good combustion practices.

(e) The opacity of the startup gas heater shall not exceed 20% (6-minute average), except for one 6-minute period per hour of not more than 27%. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

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

D.5.2 Record Keeping Requirements

(a) To document compliance with Condition D.5.1(b), the Permittee shall maintain monthly fuel usage records of natural gas combusted in startup heater GH1.

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

D.5.3 Reporting Requirements

A quarterly summary of the information to document compliance with Condition D.5.1(b) 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).

SECTION D.6 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] - Insignificant Activities

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

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

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

D.6.1 Volatile Organic Compounds (VOC) [326 IAC 8-3-2]

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

(a) Equip the cleaner with a cover;

(b) Equip the cleaner with a facility 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 manner that greater than twenty percent (20%) of the waste solvent (by weight) can evaporate into the atmosphere.

D.6.2 Volatile Organic Compounds (VOC) [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 facility 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 facility must be internal such that articles are enclosed under the cover while draining. The drainage facility 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°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 owner or operator of a cold cleaning facility construction of which commenced after July 1, 1990, 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.

SECTION E **TITLE IV CONDITIONS**

Facility Description [326 IAC 2-7-5(15)]

(a) Four (4) natural gas-fired combustion turbine generators, identified as units CT1, CT2, CT3, and CT4, commenced construction in 2001, each with a maximum heat input capacity of 1,906.4 MMBtu/hr (higher heating value), equipped with low NOx burners, controlled by four (4) selective catalytic reduction (SCR) systems (SCR11, SCR12, SCR21 and SCR22), and exhausting to stacks S1, S2, S3 and S4, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The combined nominal power output is 1,130 megawatts (MW). Under 40 CFR Part 60, Subpart GG, turbines CT1 through CT4 are considered stationary gas turbines.

(b)* Four (4) heat recovery steam generators, identified as units HRSG1, HRSG2, HRSG3, and HRSG4, commenced construction in 2001, equipped with natural gas fired duct burners, each with a maximum heat input capacity of 310 MMBtu/hr (higher heating value), controlled by four (4) SCR systems (SCR11, SCR12, SCR21 and SCR22), and exhausting to stacks S1, S2, S3, and S4, respectively. Each stack has CEMs for NOx and CO. Under 40 CFR Part 60, Subpart Da, the duct burners are considered steam generating units.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners which are a source of emissions.

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

Acid Rain Program

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

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

E.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 - NO_x Budget Permit for NO_x Budget Units Under 326 IAC 10-4-1(a)

Facility Description [326 IAC 2-7-5(15)]

(a) Four (4) natural gas-fired combustion turbine generators, identified as units CT1, CT2, CT3, and CT4, commenced construction in 2001, each with a maximum heat input capacity of 1,906.4 MMBtu/hr (higher heating value), equipped with low NOx burners, controlled by four (4) selective catalytic reduction (SCR) systems (SCR11, SCR12, SCR21 and SCR22), and exhausting to stacks S1, S2, S3 and S4, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The combined nominal power output is 1,130 megawatts (MW). Under 40 CFR Part 60, Subpart GG, turbines CT1 through CT4 are considered stationary gas turbines.

(b)* Four (4) heat recovery steam generators, identified as units HRSG1, HRSG2, HRSG3, and HRSG4, commenced construction in 2001, equipped with natural gas fired duct burners, each with a maximum heat input capacity of 310 MMBtu/hr (higher heating value), controlled by four (4) SCR systems (SCR11, SCR12, SCR21 and SCR22), and exhausting to stacks S1, S2, S3, and S4, respectively. Each stack has CEMs for NOx and CO. Under 40 CFR Part 60, Subpart Da, the duct burners are considered steam generating units.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners which are a source of emissions.

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

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

This NOx 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 owners and operators 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: CT1, CT2, CT3, and CT4.

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

(a) The owners and operators and, to the extent applicable, the NOx authorized account representative of the NOx budget source and each NOx 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 NOx 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 owners and operators of the NOx budget source and each NOx budget unit at the source shall hold NOx allowances available for compliance deductions under 326 IAC 10-4-10(j), as of the NOx allowance transfer deadline, in each unit's compliance account and the source's overdraft account in an amount:

(1) Not less than the total NOx 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 NOx budget trading program, or a change in regulatory status of a NOx budget opt-in unit.

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

(c) NOX allowances shall be held in, deducted from, or transferred among NOx 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.

(d) A NOx 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 NOx allowance was allocated.

(e) A NOx allowance allocated under the NOx budget trading program is a limited authorization to emit one (1) ton of NOx in accordance with the NOx budget trading program. No provision of the NOx budget trading program, the NOx budget permit application, the NOx 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.

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

(g) 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 NOx allowance to or from each NOx 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 NOx budget permit of the NOx budget unit by operation of law without any further review.

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

The owners and operators of each NOx budget unit that has excess emissions in any ozone control period shall do the following:

(a) Surrender the NOx 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 owners and operators of the NOx budget source and each NOx budget unit at the source shall keep, either on site at the source or at a central location within Indiana for those owners or operators with unattended sources, each of the following documents for a period of five (5) years:

(a) The account certificate of representation for the NOx authorized account representative for the source and each NOx 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 owners or operators 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 NOx 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 NOx budget trading program.

(d) Copies of all documents used to complete a NOx budget permit application and any other submission under the NOx budget trading program or to demonstrate compliance with the requirements of the NOx 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 NOx authorized account representative of the NOx budget source and each NOx budget unit at the source shall submit the reports and compliance certifications required under the NOx 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 NOx authorized account representative: "I am authorized to make this submission on behalf of the owners and operators of the NOx budget sources or NOx 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 NOx authorized account representative shall submit required information to:

Indiana Department of Environmental Management
Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

(d) Where 326 IAC 10-4 requires a submission to U.S. EPA, the NOx 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 owners and operators of each NOx budget source shall be liable as follows:

(a) Any person who knowingly violates any requirement or prohibition of the NOx budget trading program, a NOx 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 NOx 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 NOx budget trading program that occurs prior to the date that the revision takes effect.

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

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

(f) Any provision of the NOx budget trading program that applies to a NOx budget unit, including a provision applicable to the NOx authorized account representative of a NOx 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 owners and operators and the NOx authorized account representative of one (1) NOx budget unit shall not be liable for any violation by any other NOx budget unit of which they are not owners or operators or the NOx authorized account representative and that is located at a source of which they are not owners or operators or the NOx authorized account representative.

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

No provision of the NOx budget trading program, a NOx budget permit application, a NOx budget permit, or an exemption under 326 IAC 10-4-3 shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the NOx authorized account representative of a NOx budget source or NOx 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: PSEG Lawrenceburg Energy Company, LLC
Source Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.: T029-18580-00033

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
Indianapolis, Indiana 46204-2251
Phone: 317-233-0178
Fax: 317-233-6865

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: PSEG Lawrenceburg Energy Company, LLC
Source Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.: T029-18580-00033

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

☐ This is an emergency as defined in 326 IAC 2-7-1(12)

- X 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
- X 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, NOx, 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 Quarterly Report

Source Name:	PSEG Lawrenceburg Energy Company, LLC
Source Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.:	T029-18580-00033
Facility:	Combustion Turbine CT1
Parameter:	NOx emissions
Limit:	Less than 78.1 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

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: PSEG Lawrenceburg Energy Company, LLC
Source Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.: T029-18580-00033
Facility: Combustion Turbine CT2
Parameter: NOx emissions
Limit: Less than 78.1 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

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:	PSEG Lawrenceburg Energy Company, LLC
Source Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.:	T029-18580-00033
Facility:	Combustion Turbine CT3
Parameter:	NOx emissions
Limit:	Less than 78.1 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

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: PSEG Lawrenceburg Energy Company, LLC
Source Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.: T029-18580-00033
Facility: Combustion Turbine CT4
Parameter: NOx emissions
Limit: Less than 78.1 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

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: ______________________

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

Part 70 Quarterly Report

Source Name:	PSEG Lawrenceburg Energy Company, LLC
Source Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.:	T029-18580-00033
Facility:	Combustion Turbine CT1
Parameter:	CO emissions
Limit:	Less than 102.21 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

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: PSEG Lawrenceburg Energy Company, LLC
Source Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.: T029-18580-00033
Facility: Combustion Turbine CT2
Parameter: CO emissions
Limit: Less than 102.21 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

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:	PSEG Lawrenceburg Energy Company, LLC
Source Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.:	T029-18580-00033
Facility:	Combustion Turbine CT3
Parameter:	CO emissions
Limit:	Less than 102.21 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

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:	PSEG Lawrenceburg Energy Company, LLC
Source Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.:	T029-18580-00033
Facility:	Combustion Turbine CT4
Parameter:	CO emissions
Limit:	Less than 102.21 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

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:	PSEG Lawrenceburg Energy Company, LLC
Source Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.:	T029-18580-00033
Facility:	Combustion Turbines CT1 through CT4
Parameter:	Total startup and shutdown period
Limit:	Less than 2,240 hours per twelve (12) consecutive month period with compliance determined at the end of each month.

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: PSEG Lawrenceburg Energy Company, LLC
Source Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.: T029-18580-00033
Facility: Auxiliary Boiler
Parameter: Natural Gas Usage
Limit: Less than 122.2 MMSCF per twelve (12) consecutive month period with Compliance determined at the end of each month.

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: PSEG Lawrenceburg Energy Company, LLC
Source Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.: T029-18580-00033
Facility: Diesel Backup Electric Generator
Parameter: Diesel Fuel Usage
Limit: Less than 35,252 gallons per twelve (12) consecutive month period with Compliance determined at the end of each month.

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: PSEG Lawrenceburg Energy Company, LLC
Source Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.: T029-18580-00033
Facility: Diesel Fire Pump
Parameter: Diesel Fuel Usage
Limit: Less than 7,554 gallons per twelve (12) consecutive month period with Compliance determined at the end of each month.

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:	PSEG Lawrenceburg Energy Company, LLC
Source Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.:	T029-18580-00033
Facility:	Startup Heater (GH1)
Parameter:	Natural Gas Usage
Limit:	Less than 5.3 MMSCF per twelve (12) consecutive month period with Compliance determined at the end of each month.

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: PSEG Lawrenceburg Energy Company, LLC
Source Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
Part 70 permit No.: T029-18580-00033

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.

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (TSD) for a Part 70 Operating Permit

Source Background and Description

Source Name:	PSEG Lawrenceburg Energy Company, LLC
Source Location:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
County:	Dearborn
SIC Code:	4911
Operation Permit No.:	T029-18580-00033
Permit Reviewer:	ERG/YC

On March 23, 2006, the Office of Air Quality (OAQ) had a notice published in the Dearborn County Register, Lawrenceburg, Indiana, stating that PSEG Lawrenceburg Energy Company, LLC had applied for a Part 70 Operating Permit to operate an electric generating plant with control. The notice also stated that OAQ proposed to issue a permit for this operation and provided information on how the public could review the proposed permit 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 permit should be issued as proposed.

On April 19, 2006, PSEG Lawrenceburg Energy Company, LLC submitted comments on the proposed Part 70 Operating Permit. The summary of the comments is as follows. New language is shown in bold and deleted language is shown in strikeout. The Table of Contents has been changed as necessary.

Comment 1:

The draft permit was addressed to Mr. Tom Wehrenberg at the PSEG Waterford, Ohio facility. Future correspondence should be addressed to the General Manager at the PSEG Lawrenceburg plant address.

Response to Comment 1:

As requested by the Permittee, future correspondence will be addressed to the General Manager at the PSEG plant in Lawrenceburg, Indiana.

Comment 2:

Condition D.1.1(a): PSEG requests that the ammonia limit contained in this table be removed. Ammonia is not regulated under National Ambient Air Quality Standards ("NAAQS"), is not a hazardous air pollutant ("HAP"), nor is it regulated under any Indiana Air Pollution Control board rules. PSEG does not believe that the Indiana Department of Environmental Management ("IDEM") has the authority to impose this limit. IDEM cites the Prevention of Significant Deterioration ("PSD") construction permit as the basis for this limit. However PSEG finds no regulatory basis for the inclusion of this limit in its PSD permit because ammonia is not a PSD-regulated pollutant.

Response to Comment 2:

Ammonia is used with the operation of SCR units. The emission limit for ammonia was established in the construction permit #029-12517-00033, issued on June 7, 2001 and was included in the permit to protect public health from adverse ammonia impacts. The ammonia emission analysis is part of the environmental impact analysis for the NOx BACT at this source. As stated in Condition D.1.13 in CP #029-12517-00033, issued on June 7, 2001, this condition was established based on the authority provided by 326 IAC 2-1.1-5 (Air Quality Requirements). For clarification purposes, Condition D.1.1 has been revised as follows:

D.1.1 PSD BACT Requirements [326 IAC 2-2-3] **[326 IAC 2-1.1-5]**

Pursuant to CP #029-12517-00033, originally issued on June 7, 2001, ~~and~~ 326 IAC 2-2-3 (PSD BACT)**, and 326 IAC 2-1.1-5 (Air Quality Requirements)**, the Permittee shall comply with the following requirements:

. . .

Comment 3:

Condition D.1.1(j) – This condition defines “startup” and “shutdown” as “less than fifty (50) percent load”. PSEG requests that this definition be changed to more accurately reflect the actual point at which the operating mode of the unit changes from “startup” mode to normal operation mode and from normal operation mode to “shutdown” mode. The existing permit language is inherently dependent upon the megawatt (“MW”) output of the generator rather than the mode of operation of the combustion process.

PSEG states that the combustion turbines installed at PSEG Lawrenceburg Energy Facility are General Electric (“GE”) Frame 7FA’s with GE’s most advanced Dry-Low NOx (“DLN”) technology. GE refers to this technology as “DLN-2.6”. PSEG included as part of this comment a technical paper from GE Power Systems that describes DLN-2.6 in greater detail and shows that the emissions performance of DLN-2.6 depends on the operational mode of the turbines. These issues are specifically addressed on page 14 of the GE document.

PSEG states that while the GE authors also refer to the 50% load range, there are problems in using this definition in a permitting context. By far, the largest problem lies in defining “50% load”, because it is subject to varying interpretations. Since the current definition is defined by the output of the generator, one method is to use 50% of the rated capacity of the generator. However, this method is flawed because this value is higher than the maximum capability of the combustion turbine/generator system as a whole.

PSEG further states that using the maximum capability of the combustion turbine is also problematic because it varies significantly with ambient and operational conditions (temperature, pressure, humidity, inlet air cooling, etc.). Due to this variability, PSEG states that it is commonplace in the combustion turbine industry to cite technical data corrected to the standard conditions of 59^{O}F, 14.696 psia, 60% relative humidity. Furthermore, the combustion turbine capability data supplied to the facility by GE is in the form of a “guarantee point” (at standard conditions) and multi-dimensional correction curves. Actual generator output is generally higher than the guarantee point plus or minus corrections.

PSEG proposes the language below as the definition of “startup” and “shutdown” periods. Similar language is used to define startup and shutdown for a similar GE 7FA combined-cycle combustion turbine installation in Ohio (Duke Energy Washington County LLC, Ohio EPA Permit to Install Number 06-06792):

“Startup is defined as the period beginning with the commencement of combustion in the combustion turbine and ending when the combustion turbine achieves operational Mode 6. Shutdown is defined as the period beginning when the combustion turbine leaves operational Mode 6 and ending when combustion has ceased. Mode 6 is defined by the manufacturer as the low emissions mode for steady-state operation. The continuous emissions monitoring system will record the status of combustion turbine operational Mode 6, including when the emissions unit is in startup, Mode 6, or shutdown modes.”

PSEG states that the above language eliminates the problems and uncertainties inherent in the existing startup and shutdown definitions. The proposed definitions are linked to a specific operational mode based on the status of the combustion process, a mode that is easily tracked by the units' control systems. This operational mode (referred to as "Mode 6" or "Mode 6Q") is the normal operating mode of the combustion turbines' DLN-2.6 technology. Operating experience has shown that the point at which this operating mode is reached coincides with approximately 50% load. Furthermore, loads above approximately 50% cannot be achieved when in the lower modes of operation (Modes 1-5). Emissions from the combustion turbine are at their lowest when operating in Mode 6.

PSEG concludes that this minor change in the definitions of startup and shutdown will not increase the duration of the startup or shutdown cycles nor increase the emissions produced, and therefore a Best Available Control Technology ("BACT") evaluation to support this language change is not required.

Comment 4:

Condition D.1.1(j)(1) – This condition restricts each startup or shutdown period to 3.5 hours or less. PSEG stated that in other similar permits, IDEM has defined an "event" as exactly one (1) startup and one (1) shutdown period. PSEG requests that this condition be changed to either:

(1) Limit the total time for a startup and shutdown event to seven (7) hours; or

(2) Limit the startup period to five (5) hours and the shutdown period to two (2) hours, such that the total event time would still be seven (7) hours.

The emission factors are the same for both the startup and shutdown periods. Since PSEG is only asking for an adjustment to the allocation of the hours and not to the total hours, the emissions from the event will remain unchanged. If IDEM requires additional information on the required steps and associated time requirements necessary to startup or shutdown the system, this information can be provided. Note that this condition also limits the facility to a total of 2,240 turbine hours per year for startups and shutdowns. PSEG is not requesting a change to these total hours.

Response to Comments 3 and 4:

The startup and shutdown requirements in Condition D.1.1(j) are PSD BACT requirements for the combustion turbines CT-1, CT-2, CT-3, and CT-4. In order to revise PSD BACT requirements, PSEG would have to submit a revised PSD BACT analysis for consideration by the Department. PSEG has not submitted a revised PSD BACT for these units; therefore, no changes have been made as a result of these comments.

Comment 5:

Condition D.1.2(a): This condition establishes a formaldehyde limit of 0.00013 lbs/MMBtu from each of the combustion turbines and notes that HAP emissions from the source are below the major source thresholds. PSEG does not believe that the formaldehyde limit in this permit is appropriate and requests that it be removed. Although this limit was contained in the original PSD permit for the facility, PSEG believes that this limit should not have been included as 1) there is no NAAQS or PSD air quality increment for formaldehyde, and 2) there are no specific state or federal rules applicable to the control of formaldehyde emissions. PSEG provided an emission factor for formaldehyde (verified through stack testing) that demonstrates that the facility does not have potential HAP emissions above major source thresholds.

PSEG notes that Maximum Achievable Control Technology ("MACT") Subpart YYYY (40 CFR 63.6080 et seq.) regulates formaldehyde emissions from certain combustion turbines located at major HAP sources. However, MACT Subpart YYYY is not applicable to the stationary combustion turbines at the facility because the facility is not a major HAP source. Even if the facility were a major HAP source, pursuant to 40 CFR 63.6090(b)(4), "Existing stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart and of subpart A of this part…". 40 CFR 63.6090(a)(1) indicates that "…a stationary combustion turbine is existing if you commenced construction or reconstruction of the stationary combustion turbine on or before January 14, 2003…". The combustion turbines at the facility commenced construction in July 2001, prior to the January 14, 2003 applicability deadline. Hence, MACT Subpart YYYY is not applicable not only because the facility is not a major HAP source, but also because the combustion turbines commenced construction prior to the January 14, 2003 applicability deadline.

PSEG requests that the proposed wording in Condition D.1.2 be replaced with the following:

"The potential to emit hazardous air pollutants (HAPS) from the combustion turbines is limited to less than 10 tons/yr for a single HAP and less than 25 tons/yr for total HAPs. This was demonstrated through emission calculations submitted in the CP #029-12517-00033 permit application. Performance testing conducted within 180 days of first-fire confirmed that the facility does not have potential HAP emissions above major source thresholds, qualifying the combustion turbines as HAP minor sources not subject to 326 IAC 2-4.1."

PSEG also requests that this change be made on page 12 of the Technical Support Document under the discussion of 326 IAC 2-4.1.

Comment 6:

Condition D.1.2(c): This condition discusses NOx emission limits for the unit. However, Condition D.1.2 is titled "HAP Limitations". PSEG does not believe paragraph (c) is intended to be included under this condition, so it should either be eliminated or made a separate condition in the permit.

Response to Comments 5 and 6:

40 CFR 63, Subpart YYYY (National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines) applies to "… any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions." Under 40 CFR 63.6090(a), existing stationary combustion turbines are defined as those for which construction or reconstruction was commenced on or before January 14, 2003. New and reconstructed stationary combustion turbines are defined as those that were constructed or reconstructed after January 14, 2003. Since the turbines at this source were constructed prior to the January 14, 2003, IDEM, OAQ agrees with PSEG's determination that the turbines located at this plant would meet the definition of existing stationary combustion turbines in this rule. If the HAP emissions for the source ever exceed the major source thresholds, these units would be *affected units* under this rule (i.e., subject to this NESHAP) but would be required to meet no standards or other requirements as indicated in 40 CFR 63.6090(b)(4).

However, construction of these units commenced prior to the promulgation of 40 CFR 63, Subpart YYYY (March 5, 2004). Hence, 326 IAC 2-4.1 was applicable at the time of construction of the turbines because they were constructed after July 27, 1997 and the unlimited emissions were estimated to be greater than the major source thresholds for HAPs (10 tons per year for a single HAP and 25 tons per year for total HAPs) using the emission factors in AP-42 for natural gas fired turbines. In order to ensure that the single HAP emissions from the entire source are limited to less than 10 tons per year, a formaldehyde emission limit was established in CP #029-12517-00033, originally issued on June 7, 2001 for the turbines.

According to the stack testing results on December 4 though 15, 2003 for the existing NG fired turbines, the actual formaldehyde emissions from each of the turbines are listed in the table below:

Unit	Formaldehyde Emission Rate (lbs/MMBtu) – without duct burners	Formaldehyde Emission Rate (lbs/MMBtu) – with duct burners	Worst Case Emission Rate (lbs/MMBtu)
Turbine CT1	0.00007	0.00008	0.00008
Turbine CT2	0.00012	0.00006	0.00012
Turbine CT3	0.000072	0.000072	0.000072
Turbine CT4	0.00011	0.000066	0.00011

Using the worst case emission rate for each turbine and the maximum heat input capacity for each turbine (1,906.4MMBtu/hr + 310 MMBtu/hr = 2,216.4 MMBtu/hr), the potential to emit formaldehyde from the four (4) existing turbines is equal to 3.71 tons per year ((0.00008 + 0.00012 + 0.000072 + 0.00011) lbs/MMBtu x 2,216.4 MMBtu/hr x 8760 hr/yr x 1 ton/2000 lbs). Combined with the HAP emissions from other existing units, the potential to emit of formaldehyde for the entire source is less than 10 tons per year and the potential to emit total HAPs is less than 25 tons per year. Therefore, this existing source is a minor source for HAPs and the requirements in Conditions D.1.2(a) and (b) are no longer necessary and can be removed from the permit.

Condition D.1.2(c) provides the NOx emission limitations for 40 CFR 60, Subpart Da. The applicable requirements for 40 CFR 60, Subpart Da are included in Condition D.1.13. Condition D.1.2(c) was included in Condition D.1.2 in error.

Therefore, Condition D.1.2 has been removed from the permit and subsequent conditions in Section D.1 have been renumbered.

~~D.1.2 HAP Limitations [326 IAC 2-4.1]~~

~~(a) In order to make the requirements of 326 IAC 2-4.1 (MACT) not applicable and pursuant to CP #029-12517-00033, originally issued on June 7, 2001, the formaldehyde emissions from each of the combustion turbines (CT1, CT2, CT3, and CT4) shall not exceed 0.00013 lbs/MMBtu.~~

~~(b) Combined with the HAP emissions from other existing source, the HAP emissions from the entire source are limited to less than 10 tons/yr for a single HAP and less than 25 tons for total HAPs. Therefore, the requirements of 326 IAC 2-4.1 are not applicable to this source.~~

~~(c) Pursuant to 40 CFR 60.44Da(d)(1), NOx emissions shall not exceed 1.6 pounds per megawatt-hour gross energy output, based on a 30-day rolling average, except as provided under 40 CFR 60.48Da(k)(1).~~

Comment 7:

In various parts of the permit, IDEM references subsections of 40 CFR Part 60 and 326 IAC as applicable to the source. However, sections D.1.12 and D.1.14 contain extracts of 7 to 14 pages, respectively, of regulatory text from 40 CFR Part 60, Subparts GG and Da. PSEG asked how Conditions D.1.12 and D.1.14 will be impacted in the event of a regulatory change, i.e. whether the current Subpart GG and Da versions extracted and included in the permit <u>or</u> the revised sections will apply. This comment also applies to Section D.2.8, which includes an extract of about 6 pages of text from 40 CFR Part 60, Subpart Db.

Response to Comment 7:

326 IAC 12 incorporates the New Source Performance Standards (NSPS); however, the version of the federal rules referenced in 326 IAC 12 is defined in 326 IAC 1-1-3. Currently, 326 IAC 1-1-3 incorporates the July 1, 2005 version of the Federal rules. Although IDEM regularly revises 326 IAC 1-1-3 to incorporate more recent versions of the CFR, revisions to specific federal rules may not be incorporated into the State regulations for several months. During these periods, both the version of the federal rule referenced by 326 IAC 12 and 326 IAC 1-1-3 (currently the July 1, 2005 version) and the revised federal rule in the current version of 40 CFR Part 60 apply. Where the emission limitations conflict, the source need only comply with the more stringent requirements. In order to keep the permit up-to-date, PSEG should submit an application to IDEM, OAQ for a permit modification, whenever 40 CFR 60, Subparts GG or Da are revised.

Comment 8:

Condition D.1.13: This condition references one-time testing required under New Source Performance Standards (NSPS). PSEG has completed this testing, and requests that the requirement be removed from the permit or that a notation be included in the permit that the referenced testing has already been performed.

Comment 9:

Condition D.1.15 – This condition references one-time testing required under NSPS for the duct burners. PSEG has completed this testing, and requests that the requirement be removed from the permit or that a notation be included in the permit that the referenced testing has already been performed.

Response to Comments 8 and 9:

IDEM, OAQ agrees that these conditions are no longer necessary. The following changes have been made to Condition D.1.13 and D.1.15. Subsequent conditions have been renumbered.

~~D.1.13 One Time Deadlines Relating to New Source Performance Standards for Electric Utility Steam Generating Units for Stationary Gas Turbines [40 CFR Part 60, Subpart GG]~~

~~The Permittee must conduct the initial performance tests Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup of the four (4) natural gas combustion turbines CT1 through CT4.~~

~~D.1.15 One Time Deadlines Relating to New Source Performance Standards for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 [40 CFR Part 60, Subpart Da]~~

~~The Permittee must conduct the initial performance tests Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup of the four (4) duct burners associated with the heat recovery steam generators HRSG1 through HRSG4.~~

Comment 10:

Condition D.3.2 – This condition requires that the emergency generators meet a particulate matter limit of 0.03 grains per dry standard cubic foot (gr/dscf). PSEG does not believe this limit was intended to apply to emergency generators as these units do not have potential particulate matter emissions above 100 tons per year or actual particulate matter emissions above 10 tons per year, as provided under 326 IAC 6.5-1-1(a)(2). PSEG requests that this condition be removed. PSEG also requests that this change be made in the Technical Support Document on page 15 under the heading "State Rule Applicability – Emergency Generators (Insignificant Activities)".

Response to Comment 10:

326 IAC 6.5-1-1(a)(2) states the limitations in 326 IAC 6.5-2 apply if the "source or facility" has the potential to emit greater than or equal to 100 tons per year of particulate, or the actual emissions of particulate are greater than or equal to 10 tons per year. The term "facility" is defined in 326 IAC 1-2-27 and refers to the individual emission units, while the term "source" is defined in 326 IAC 1-1-73 and refers to the entire plant. Hence, the limitations in 326 IAC 6.5-2 apply to individual emission units if the potential emissions from either the emission unit or the entire plant are greater than 100 tons per year, or the actual emissions from an individual emission unit or the entire plant are greater than 10 tons per year. In the case of PSEG's Lawrenceburg plant, the potential emissions of particulate from the entire source are greater than 100 tons per year. Therefore, the requirements of 326 IAC 6.5-2 apply to the emergency generators at this source. Compliance with these limitations would be determined using stack testing. However, IDEM, OAQ is not at this time requiring PSEG to complete stack testing for these units. No changes have been as a result of these comments.

Comment 11:

Condition D.4.2: This condition requires that the cooling towers meet a particulate matter limit of 0.03 gr/dscf. PSEG does not believe that this limit was intended to apply to cooling towers, as there is no practical way to measure cooling tower emissions to demonstrate compliance with this limit. PSEG requests that this condition be removed. In the event that IDEM includes this limit in the Title V permit, PSEG requests guidance on how compliance with such a limit could be determined.

Response to Comment 11:

Since the emissions from the cooling towers are considered fugitive emissions, PM emissions from the cooling towers are not subject to the PM limit in 326 IAC 6.5-1-2 (0.03 gr/dscf). Therefore, Condition D.4.2 has been removed and Condition D.4.3 has been revised as follows:

~~D.4.2 PM Limitations [326 IAC 6.5-1-2]~~

~~Pursuant to 326 IAC 6.5-1-2(a) (formerly 326 IAC 6-1-2(a)), particulate matter (PM) from each of the cooling towers shall not exceed 0.03 grain per dry standard cubic foot (gr/dscf) of exhaust air.~~

D.4.~~3~~**2** Particulate Control

In order to comply with Condition~~s~~ D.4.1(a) ~~and D.4.2~~, the high efficiency drift eliminators for particulate control shall be in operation and control emissions from the cooling towers at all times that the facilities are in operation.

Upon further review, IDEM, OAQ has decided to make the following changes:

1. IDEM has decided to remove (d) concerning nonroad engines from B.18 Permit Amendment or Modification. 40 CFR 89, Appendix A specifically indicates that states are not precluded from regulating the use and operation of nonroad engines, such as regulations on hours of usage, daily mass emission limits, or sulfur limits on fuel; nor are permits regulating such operations precluded, once the engine is no longer new.

B.18 Permit Amendment or Modification [326 IAC 2-7-11] [326 IAC 2-7-12][40 CFR 72]

…

~~(e) No permit amendment or modification is required for the addition, operation or removal of a nonroad engine, as defined in 40 CFR 89.2.~~

2. There was an extra sentence in Condition B.10. Therefore, Condition B.10 has been corrected as follows:

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 prepare and maintain Preventive Maintenance Plans (PMPs) within ninety (90) days ~~(this time frame is determined on a case by case basis but no more than ninety (90) days)~~ after issuance of this permit, for the sources as described in 326 IAC 1-6-3. At a minimum, the PMP shall include:

. . .

3. The number in Condition C.19 has been corrected as follow:

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

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

(~~b~~**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.

4. The phone number and the fax number listed in Emergency Provisions have been changed so that the OAQ's receptionist number is listed and the fax number for the compliance branch is listed. These numbers have been changed as shown throughout the permit.

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

. . .

(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:
. . .

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance Section), or
Telephone Number: 317-233-~~5674~~**0178** (ask for Compliance Section)
Facsimile Number: 317-233-~~5967~~**6885**.

. . .

5. Condition C.17 (General Record Keeping Requirements) and C.18 (General Reporting Requirements) have been revised as follows to include the definitions in both the provisions of 326 IAC 2-2 (PSD) and 326 IAC 2-3 (Emission Offset):

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

. . .

(c) If there is a reasonable possibility 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 Clean Unit, 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) 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:

. . .

(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:

. . .

(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)(iii)**; and

. . .

C.18 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2] **[326 IAC 2-3]**

. . .

(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 electric utility steam generating unit, then for that project the Permittee shall:

. . .

(g) 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 other than Electric Utility Steam Generating 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 that 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) ~~(Select citations as applicable)~~, for that regulated NSR pollutant, and

. . .

(h) The report for the project at an existing emissions unit other than an electric utility steam generating unit shall be submitted within sixty (60) days after the end of the year and contain the following:

. . .

(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)**.

. . .

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Operating Permit

Source Background and Description

Source Name:	PSEG Lawrenceburg Energy Company, LLC
Source Location:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
County:	Dearborn
SIC Code:	4911
Operation Permit No.:	T029-18580-00033
Permit Reviewer:	ERG/YC

The Office of Air Quality (OAQ) has reviewed a Part 70 Operating Permit application from PSEG Lawrenceburg Energy Company, Inc. relating to the operation of an electric generating plant.

This Part 70 operating permit contains provisions intended to satisfy the requirements of the construction permit rules.

Permitted Emission Units and Pollution Control Equipment

The source consists of the following permitted emission units and pollution control devices:

(a) Four (4) natural gas-fired combustion turbine generators, identified as units CT1, CT2, CT3, and CT4, commenced construction in 2001, each with a maximum heat input capacity of 1,906.4 MMBtu/hr (higher heating value), equipped with low NOx burners, controlled by four (4) selective catalytic reduction (SCR) systems (SCR11, SCR12, SCR21 and SCR22), and exhausting to stacks S1, S2, S3 and S4, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The combined nominal power output is 1,130 megawatts (MW). Under 40 CFR Part 60, Subpart GG, turbines CT1 through CT4 are considered stationary gas turbines.

(b)* Four (4) heat recovery steam generators, identified as units HRSG1, HRSG2, HRSG3, and HRSG4, commenced construction in 2001, equipped with natural gas fired duct burners, each with a maximum heat input capacity of 310 MMBtu/hr (higher heating value), controlled by four (4) SCR systems (SCR11, SCR12, SCR21 and SCR22), and exhausting to stacks S1, S2, S3, and S4, respectively. Each stack has CEMs for NOx and CO. Under 40 CFR Part 60, Subpart Da, the duct burners are considered steam generating units.

(c) One (1) natural gas fired auxiliary boiler, identified as Auxiliary Boiler, commenced construction in 2001, with a maximum heat input capacity of 114.6 MMBtu/hr, equipped with a low NOx burner, and exhausting to stack S5. Under 40 CFR Part 60, Subpart Db, the auxiliary boiler is considered a steam generating unit.

*Note: The heat recovery steam generators are not a source of emissions. They have been included for clarity as they are a part of the entire source and operate in conjunction with the duct burners which are a source of emissions.

Unpermitted Emission Units and Pollution Control Equipment

There are no unpermitted emission units operating at this source during this review process.

Insignificant Activities

The source also consists of the following insignificant activities, as defined in 326 IAC 2-7-1(21):

(a) Diesel emergency generators not exceeding 1,600 horsepower [326 IAC 2-2-3]:

(1) One (1) diesel backup electric generator, commenced construction in 2001, with a maximum power output of 1,000 kilowatts (1,342 horsepower), and exhausting to stack S8.

(2) One (1) diesel fire pump, commenced construction in 2001, with a maximum power output of 265 horsepower (hp), and exhausting to stack S9.

(b) Forced and induced draft cooling tower system not regulated under a NESHAP, including two (2) cooling towers, identified as Cooling Tower 1 and Cooling Tower 2, commenced construction in 2001, each equipped with a high efficiency drift eliminator for PM control, and exhausting to stacks S6 and S7, respectively. [326 IAC 2-2-3] [326 IAC 6.5-1-2]

(c) Natural gas-fired combustion sources with heat input equal to or less than ten million (10,000,000) Btu per hour, including one (1) startup gas heater, identified as GH1, commenced construction in 2003, with a maximum heat input capacity of 2.4 MMBtu/hr, and exhausting to stack GH1. [326 IAC 2-2-3]

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

(e) Paved and unpaved roads and parking lots with public access [326 IAC 6-4].

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

(g) Fuel oil-fired combustion sources with heat input equal to or less than two million (2,000,000) Btu per hour and firing fuel containing less than five tenths (0.5) percent sulfur by weight.

(f) Equipment powered by internal combustion engines of capacity equal to or less than 500,000 Btu/hour, except where total capacity of equipment operated by one stationary source exceeds 2,000,000 Btu/hour.

(g) Combustion source flame safety purging on startup.

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

(i) Filling drums, pails or other packaging containers with lubricating oils, waxes and greases.

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

(k) Closed loop heating and cooling systems.

(l) Two (2) steam turbines, identified as ST1 and ST2, constructed in 2001.

(l) Activities associated with the treatment of wastewater streams with an oil and grease content less than or equal to 1% by volume.

(m) Any operation using aqueous solutions containing less than 1% by weight VOCs excluding HAPs.

(n) Water based adhesives that are less than or equal to 5% by volume of VOCs excluding HAPs.

(o) Heat exchanger cleaning and repair.

(p) Process vessel degassing and cleaning to prepare for internal repairs.

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

(r) Flue gas conditioning systems and associated chemicals such as the following: sodium sulfate; ammonia; and sulfur trioxide.

(s) 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.

(t) Blowdown for any of the following: sight glass; boiler; compressors; pumps; and cooling tower.

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

(v) Purge double block and bleed valves.

(w) Filter or coalescer media changeout.

(x) A laboratory as defined in 326 IAC 2-7-1(21)(D).

Existing Approvals

The source has constructed or has been operating under the following previous approvals:

(a) CP #029-12517-00033, issued on June 7, 2001.

(b) Acid Rain Permit #029-12561-00033, issued on June 25, 2001.

(c) Notice-Only-Change #029-16091-00033, issued on July 3, 2002.

(d) Minor Permit Revision #029-15867-00033, issued on August 30, 2002.

(e) Significant Modification #029-16235-00033, issued on December 23, 2002.

(f) Notice-Only-Change #029-16780-00033, issued on February 19, 2003.

(g) Minor Permit Revision #029-18381-00033, issued on January 22, 2004.

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.

The following terms and conditions from previous approvals have been revised in this Part 70 operating permit:

(a) The Permittee stated that the maximum heat input capacity of the auxiliary boiler was incorrectly listed as 124.6 MMBtu/hr. The correct maximum heat input capacity for this boiler should be 114.6 MMBtu/hr. Therefore, the unit description for this boiler has been changed. This change does not change the rule applicability of this unit and does not affect any of the existing permit conditions.

(b) Condition D.2.2(a) in CP #029-12517-00033, issued on June 7, 2001:

"Pursuant to 326 IAC 2-2 (PSD), PM and PM10 emissions from the auxiliary boiler shall not exceed 0.928 lbs/hr."

According to the BACT analysis document attached to the TSD of in CP #029-12517-00033, issued on June 7, 2001, the BACT determined for the PM and PM10 emissions from the auxiliary boiler is 0.0075 lbs/MMBtu, which is equivalent to 0.928 lbs/hr with the maximum heat input capacity of 124.6 MMBtu/hr. Since the maximum heat input capacity for this boiler is 114.6 MMBtu/hr, instead of 124.6 MMBtu/hr, and the BACT limits for all other pollutants are based on a unit of lbs/MMBtu, the PM/PM10 emission limit for this boiler has been revised to 0.0075 lbs/MMBtu in this Part 70 operating permit.

The following terms and conditions from previous approvals have been determined no longer applicable; therefore, were not incorporated into this Part 70 operating permit:

(a) All construction conditions from all previously issued permits.

Reason not incorporated: All facilities previously permitted have already been constructed; therefore, the construction conditions are no longer necessary as part of the operating permit. Any facilities that were previously permitted but have not yet been constructed would need new pre-construction approval before beginning construction.

Enforcement Issue

There are no enforcement actions pending.

Recommendation

The staff recommends to the Commissioner that the Part 70 operating permit 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 administratively complete Part 70 operating permit renewal application for the purposes of this review was received on February 25, 2004. Additional information was received on March 26, 2004 and December 9, 2004.

There was no notice of completeness letter mailed to the Permittee.

Emission Calculations

See Appendix A of this document for detailed emission calculations (pages 1 through 8).

Potential to Emit of the Source

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as "the maximum capacity of a stationary source or emissions unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U.S. EPA, the department, or the appropriate local air pollution control agency."

The construction of this source was permitted in a PSD permit, CP #029-12517-00033, issued on June 7, 2001. The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any control equipment is considered enforceable only after issuance of the federally enforceable permit and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

	Potential To Emit (tons/year)						
Process/Emission Unit	PM	PM-10	SO_2	VOC	CO	NO_x	HAPs
4 Turbines (CT1, CT2, CT3, and CT4) with Duct Burners	Less than 422	Less than 422	Less than 223	Less than 135	Less than 710*	Less than 428*	Less than 9.78 for a single HAP and 23.6 for total HAPs
Anxiliary Boiler	Less than 0.49	Less than 0.49	Less than 0.37	Less than 0.33	Less than 5.01	Less than 2.20	Negligible
Backup Electric Generator (Insignificant)	Less than 0.23	Less than 0.23	Less than 0.14	Less than 0.24	Less than 1.84	Less than 8.05	Negligible
Diesel Fire Pump (Insignificant)	Less than 0.15	Less than 0.15	Less than 0.14	Less than 0.16	Less than 0.44	Less than 2.05	Negligible
2 Cooling Towers (Insignificant)	Less than 7.67	Less than 7.67	-	-	-	-	-
Startup Heater GH1 (Insignificant)	Less than 0.02	Less than 0.02	Negligible	Less than 0.01	Less than 0.22	Less than 0.37	Negligible
Other Insignificant Activities	Less than 1.0	Less than 1.0	Less than 1.0	Less than 1.0	Less than 1.0	Less than 1.0	Negligible
Total PTE of the Entire Source	Less than 432	Less than 432	Less than 225	Less than 138	Less than 719	Less than 442	Less than 9.78 for a single HAP and 23.6 for total HAPs
Title V Thresholds	NA	100	100	100	100	100	10 for a single HAP and 25 for total HAPs

Note: "-" pollutant not emitted by the facility.
(*) The emissions from each of the turbines and the associated burners, excluding startup and shutdown periods, are limited to less than 78.1 tons/yr for NOx and 102.21 tons/yr for CO, pursuant to CP #029-12517-00033, issued on June 7, 2001.

The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM-10, SO_2, VOC, CO and NOx is greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

Actual Emissions

The following table shows the actual emissions from the source. This information reflects the 2003 OAQ emission data.

Pollutant	Emissions (tons/year)
PM	3
PM-10	3
SO_2	0
VOC	0
CO	2
NOx	14

County Attainment Status

The source is located in Dearborn County.

Pollutant	Status
PM2.5	Nonattainment
PM-10	attainment
SO_2	attainment
NO_2	attainment
1-hour Ozone	attainment
8-hour Ozone	nonattainment
CO	attainment
Lead	attainment

(a) U.S.EPA in Federal Register Notice 70 FR 943 dated January 5, 2005 has designated Dearborn County as nonattainment for PM2.5. On March 7, 2005 the Indiana Attorney General's Office on behalf of IDEM filed a law suit with the Court of Appeals for the District of Columbia Circuit challenging U.S. EPA's designation of non-attainment areas without sufficient data. However, in order to ensure that sources are not potentially liable for violation of the Clean Air Act, the OAQ is following the U.S. EPA's guidance to regulate PM10 emissions as surrogate for PM2.5 emissions pursuant to the Non-attainment New Source Review requirements.

(b) 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 the ozone standards. Lawrenceburg Township in Dearborn County has been designated as nonattainment for the 8-hour ozone standard. PSEG Lawrenceburg Energy Company, LLC is located in Lawrenceburg Township. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Emission Offset, 326 IAC 2-3.

(c) Dearborn County has been classified as attainment or unclassifiable in Indiana for all other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(d) Fugitive Emissions
Since this type of operation is in one of the 28 listed source categories under 326 IAC 2-2 and there are applicable New Source Performance Standards that were in effect on August 7, 1980, the fugitive particulate matter (PM) and volatile organic compound (VOC) emissions are counted toward determination of PSD or Emission Offset review.

Part 70 Operating 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 operating permits.

(b) Monitoring and related record keeping requirements which assure that all reasonable information is provided to evaluate continuous compliance with the applicable requirements.

Federal Rule Applicability

(a) The New Source Performance Standards (NSPS) for Fossil-Fuel-Fired Steam Generators (326 IAC 12 and 40 CFR 60, Subpart D) are not applicable to this source. Pursuant to the interpretive rule published in the Federal Register on May 25, 2000, the combustion turbines are not considered to be steam generating units and, therefore, are not subject to 40 CFR 60, Subpart D. The duct burners are subject to the NSPS for Electric Utility Steam Generating Units (40 CFR 60, Subpart Da) and are exempt from the requirements of 40 CFR 60, Subpart D, pursuant to 40 CFR 60.40(e). The auxiliary boiler has a maximum heat input capacity of 114.6 MMBtu per hour, which is less than the 250 MMBtu/hr applicability threshold for this rule.

(b) The fours (4) duct burners associated with the heat recovery steam generators (HRSG1 through HRSG4) are subject to the New Source Performance Standard for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 (40 CFR 60.40Da-60.52Da, Subpart Da), which is incorporated by reference as 326 IAC 12. The four (4) duct burners are subject to the requirements of this rule because they are capable of combusting more than 250 MMBtu/hr of fossil fuel and were constructed after September 18, 1978. Since fuel is combusted in the duct burners, the heat recovery steam generators are not considered sources of emissions.

Nonapplicable portions of the NSPS will not be included in the permit. The duct burners associated with the heat recovery steam generators (HRSG1 through HRSG4) are subject to the following portions of Subpart Da:

1. 40 CFR 60.40Da(a)
2. 40 CFR 60.41Da
3. 40 CFR 60.42Da(a)(1)
4. 40 CFR 60.42Da(b)
5. 40 CFR 60.43Da(b)(2)
6. 40 CFR 60.43Da(g)
7. 40 CFR 60.44Da(d)(1)
8. 40 CFR 60.48Da(a)
9. 40 CFR 60.48Da(c)
10. 40 CFR 60.48Da(e)
11. 40 CFR 60.48Da(f)
12. 40 CFR 60.48Da(g)
13. 40 CFR 60.48Da(h)
14. 40 CFR 60.48Da(i)
15. 40 CFR 60.48Da(j)(2)
16. 40 CFR 60.48Da(k)(1)
17. 40 CFR 60.48Da(k)(2)
18. 40 CFR 60.49Da(c)(2)
19. 40 CFR 60.49Da(d)
20. 40 CFR 60.49Da(e)
21. 40 CFR 60.49Da(f)
22. 40 CFR 60.49Da(g)
23. 40 CFR 60.49Da(h)
24. 40 CFR 60.49Da(i)
25. 40 CFR 60.49Da(j)
26. 40 CFR 60.49Da(k)
27. 40 CFR 60.49Da(l)
28. 40 CFR 60.49Da(m)
29. 40 CFR 60.49Da(n)
30. 40 CFR 60.49Da(o)
31. 40 CFR 60.49Da(s)
32. 40 CFR 60.50Da(a)
33. 40 CFR 60.50Da(b)
34. 40 CFR 60.50Da(c)(1)
35. 40 CFR 60.50Da(c)(4)
36. 40 CFR 60.50Da(c)(5)
37. 40 CFR 60.50Da(d)
38. 40 CFR 60.50Da(e)
39. 40 CFR 60.50Da(f)
40. 40 CFR 60.51Da(a)

41. 40 CFR 60.51Da(b)(1)
42. 40 CFR 60.51Da(b)(2)
43. 40 CFR 60.51Da(b)(4)
44. 40 CFR 60.51Da(b)(5)
45. 40 CFR 60.51Da(b)(6)
46. 40 CFR 60.51Da(b)(7)
47. 40 CFR 60.51Da(b)(8)
48. 40 CFR 60.51Da(b)(9)
49. 40 CFR 60.51Da(c)
50. 40 CFR 60.51Da(d)
51. 40 CFR 60.51Da(f)
52. 40 CFR 60.51Da(h)
53. 40 CFR 60.51Da(i)
54. 40 CFR 60.51Da(j)
55. 40 CFR 60.51Da(k)

The combustion turbines (CT1 through CT4) at this source are subject to the NSPS for the Stationary Gas Turbines (40 CFR 60, Subpart GG) and are not subject to the requirements of 40 CFR 60, Subpart Da, pursuant to 40 CFR 60.40Da(b). The auxiliary boiler is not subject to the requirements of this subpart because the maximum heat input capacity of the boiler is less than 250 MMBtu/hr.

(c) The natural gas fired auxiliary boiler is subject to the New Source Performance Standard for Industrial-Commercial-Institutional Steam Generating Units Requirements (40 CFR 60.40b-60.49b, Subpart Db), which is incorporated by reference as 326 IAC 12. The natural gas fired auxiliary boiler is subject to the requirements of this rule because it has a maximum heat input capacity greater than 100 MMBtu/hr and was constructed after June 19, 1984.

Nonapplicable portions of the NSPS will not be included in the permit. The source has elected to comply with nitrogen oxide limitation by monitoring steam generating operating conditions to predict NOx emission rates. The natural gas fired auxiliary boiler is subject to the following portions of Subpart Db:

1. 40 CFR 60.40b(a)
2. 40 CFR 60.40b(g)
3. 40 CFR 60.40b(j)
4. 40 CFR 60.41b
5. 40 CFR 60.44b(h)
6. 40 CFR 60.44b(i)
7. 40 CFR 60.44b(l)(1)
8. 40 CFR 60.46b(c)
9. 40 CFR 60.47b(e)(1)
10. 40 CFR 60.47b(e)(4)
11. 40 CFR 60.48b(b)(1)
12. 40 CFR 60.48b(c)
13. 40 CFR 60.48b(d)
14. 40 CFR 60.48b(e)(2)
15. 40 CFR 60.48b(f)
16. 40 CFR 60.49b(a)(1)
17. 40 CFR 60.49b(b)
18. 40 CFR 60.49b(c)
19. 40 CFR 60.49b(d)
20. 40 CFR 60.49b(g)(1)
21. 40 CFR 60.49b(g)(2)
22. 40 CFR 60.49b(g)(3)
23. 40 CFR 60.49b(g)(4)
24. 40 CFR 60.49b(g)(5)
25. 40 CFR 60.49b(g)(6)
26. 40 CFR 60.49b(g)(8)

27. 40 CFR 60.49b(g)(9)
28. 40 CFR 60.49b(h)(2)(i)
29. 40 CFR 60.49b(h)(3)
30. 40 CFR 60.49b(i)
31. 40 CFR 60.49b(o)
32. 40 CFR 60.49b(v)
33. 40 CFR 60.49b(w)

The duct burners associated with the heat recovery steam generators (HRSG1 through HRSG4), which are subject to 40 CFR 60, Subpart Da, are not subject to this NSPS, pursuant to 40 CFR 60.40b(e). Pursuant to the interpretive rule published in the Federal Register on May 25, 2000, the combustion turbines CT1 through CT4 are not considered to be steam generating units and, therefore, are not subject to 40 CFR 60, Subpart Db.

(d) The four (4) natural gas-fired combustion turbines (CT1 through CT4) are subject to the New Source Performance Standard for Stationary Gas Turbines (40 CFR 60.330-60.335, Subpart GG), which is incorporated by reference as 326 IAC 12. The four (4) gas turbines are subject to the requirements of this rule because they have heat input capacities greater than 10 MMBtu/hr and were constructed after October 3, 1977.

Nonapplicable portions of the NSPS will not be included in the permit. The Permittee uses an “F” value of zero and a NOx CEMS in lieu of monitoring the nitrogen content in the fuel. On December 12, 2004, the Permittee received an approved alternative monitoring program from EPA. The (4) natural gas-fired combustion turbines (CT1 through CT4) are subject to the following portions of Subpart GG:

1. 40 CFR 60.330
2. 40 CFR 60.331
3. 40 CFR 60.332(a)(1)
4. 40 CFR 60.332(a)(3)
5. 40 CFR 60.332(b)
6. 40 CFR 60.333
7. 40 CFR 60.334(b)(1)
8. 40 CFR 60.334(b)(2)
9. 40 CFR 60.334(b)(3)
10. 40 CFR 60.334(c)
11. 40 CFR 60.334(h)(3)
12. 40 CFR 60.334(j)(1)(iii)
13. 40 CFR 60.334(j)(5)
14. 40 CFR 60.335(a)
15. 40 CFR 60.335(b)(1)
16. 40 CFR 60.335(b)(2)
17. 40 CFR 60.335(b)(3)
18. 40 CFR 60.335(b)(6)
19. 40 CFR 60.335(c)(1)

(e) The New Source Performance Standards for Volatile Organic Liquid Storage Vessels for which construction, reconstruction, or modification commenced after July 23, 1984 (326 IAC 12, 40 CFR 60.110b - 117b, Subpart Kb) are not applicable to the fuel oil storage tanks. The fuel oil storage tanks at this source have capacities less than 75 cubic meters (19,813 gallons).

(f) There are no National Emission Standards for Hazardous Air Pollutants (NESHAP)(326 IAC 14, 20 and 40 CFR Part 61, 63) included in this permit.

(g) The potential to emit HAP from from this source is limited to less than 10 tons/yr for a single HAP and less than 25 tons/yr for total HAPs. Therefore, this existing source is a HAP minor source and the requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR 63, Subpart DDDDD) are not applicable.

(h) This existing source is a HAP minor source. Therefore, the combustion turbines at this source are not subject to the NESHAP for Stationary Combustion Turbines (40 CFR 63, Subpart YYYY).

(i) The National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (40 CFR 63, Subpart ZZZZ) are not applicable to this source. This source is not a major source for HAPs.

(j) This existing source is a HAP minor source. Therefore, the cooling towers at this source are not subject to the NESHAP for Industrial Process Cooling Towers (40 CFR 63, Subpart Q).

(k) The insignificant degreasing activities are not subject to the requirements of the NESHAP for Halogenated Solvent Cleaning (40 CFR 63, Subpart T) because they do not use halogenated HAP solvents.

(l) This source is subject to the requirements of 40 CFR Part 72 through 40 CFR Part 80 (Acid Rain Program). The requirements of this program are detailed in the attached Acid Rain permit 173-12561-00033, issued on June 25, 2001, included as Appendix A to the permit.

(m) This Part 70 operating permit does involve a pollutant-specific emissions unit (combustion turbines CT1 through CT4) as defined in 40 CFR 64.1 for NOx:

(1) with the potential to emit before controls equal to or greater than the major source threshold for NOx;

(2) that is subject to an emission limitation or standard for NOx; and

(3) uses control devices (selective catalytic reduction systems) as defined in 40 CFR Part 64.1 to comply with that emission limitation or standard.

However, pursuant to 40 CFR 64.2(b)(1), any facility subject to the requirements of Sections 404 through 407(b) or 410 of the Acid Rain Program are exempt from the requirements of 40 CFR 64. Since the combustion turbines CT1 through CT4 at this source are subject to requirements of the Acid Rain Program, these units are exempt from the requirements of 40 CFR 64 (Continuous Assurance Monitoring).

State Rule Applicability – Entire Source

326 IAC 2-3 (Emission Offset)

On April 15, 2004, the United States Environmental Protection Agency (U.S. EPA) named 23 Indiana counties and one partial county nonattainment for the new 8-hour ozone standard. The designations became effective on June 15, 2004. Lawrenceburg Township in Dearborn County has been designated as nonattainment for the 8-hour ozone standard. In addition, U.S. EPA has designated Dearborn County as nonattainment for PM2.5 on January 5, 2005.

This source was constructed in 2001 and modified in 2003. Since no modifications have been completed since the effective date of the 8-hr ozone standard, this source is not subject to the requirements of 326 IAC 2-3 (Emission Offset). However, this source is classified as an Emission Offset major source because the potential to emit VOC, NOx, and PM10 is greater than 100 tons/yr from this source.

326 IAC 2-2 (Prevention of Significant Deterioration)

This electric utility generating plant was constructed in 2001 and modified in 2003. This source is in 1 of the 28 PSD source categories and has potential to emit PM, PM10, SO_2, and CO greater than 100 tons/yr. Therefore, this existing source is a PSD major source and the requirements of 326 IAC 2-2(PSD) are applicable to this source.

The construction of this source was permitted in CP #029-12517-00033, issued on June 7, 2001. When this source was permitted in 2001, the potential to emit PM, PM10, SO_2, CO, NOx, and VOC from the entire source were greater than 100 tons/yr and this construction project was reviewed as a PSD major project. The PM, PM10, SO_2, CO, NOx, and VOC emissions from this source were reviewed under the PSD rules and are required to be controlled with Best Available Control Technology (BACT).

A Significant Modification (SM) #029-16235-00033 was issued to this source on December 23, 2002 to permit the construction and operation of the startup gas heater GH1. The construction of the startup gas heater GH1 was considered part of the construction project permitted in CP #029-12517-00033, issued on June 7, 2001. Therefore, the emissions from the startup gas heaters were also required to be controlled with BACT.

Pursuant to CP #029-12517-00033, issued on June 7, 2001, SM #029-16235-00033, issued on December 23, 2002, and 326 IAC 2-2-3(PSD BACT), the Permittee shall comply with the following requirements:

For Combustion Turbines (CT1, CT2, CT3, and CT4) with Duct Burners

Pursuant to CP #029-12517-00033, originally issued on June 7, 2001, and 326 IAC 2-2-3 (PSD BACT), the Permittee shall comply with the following requirements:

(a) Emissions from each of the combustion turbines CT1, CT2, CT3, and CT4 shall comply with the following emission limits during normal combined cycle operation (50% load or more):

Pollutant	PM/PM10	NOx	CO	SO_2	VOC	Ammonia*
Duct Burner is not in Operation	21.0 lbs/hr	21.0 lbs/hr; 3 ppmvd @ 15% O_2 and 3 hour avg.	21.3 lbs/hr; 6 ppmvd @ 15% O_2 and 24 hour avg.	11.0 lbs/hr	3.0 lbs/hr	10 ppmvd @ 15% O_2 and 3 hour block avg.
Duct Burner is in Operation	24.1 lbs/hr	24.41 lbs/hr; 3 ppmvd @ 15% O_2 and 3 hour avg.	40.5 lbs/hr; 9 ppmvd @ 15% O_2 and 24 hour avg.	12.71 lbs/hr	7.7 lbs/hr	10 ppmvd @ 15% O_2 and 3 hour block avg.

*Note: Ammonia is emitted from the selective catalytic reduction (SCR) systems.

(b) The NOx emissions from each of the turbines and the associated burners, excluding startup and shutdown periods, shall not exceed 78.1 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) The CO emissions from each of the turbines and the associated burners, excluding startup and shutdown periods, shall not exceed 102.21 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(d) Each combustion turbine shall be equipped with dry low-NOx burners.

(e) A selective catalytic reduction (SCR) system shall be installed and operated at all times, except during periods of startup and shutdown.

(f) The Permittee shall use natural gas only for these units.

(g) The sulfur content of the natural gas shall not exceed two (2) grains per 100 standard cubic feet (scf).

(h) The duct burners shall not be operated until the associated combustion turbine reaches normal operation.

(i) The Permittee shall use good combustion practices.

(j) Each combustion turbine generating unit shall comply with the following startup and shutdown limitations. A startup or shutdown is defined as less than fifty (50) percent load.

(1) A startup or shutdown period shall not exceed 3.5 hours. The startup and shutdown period for all combustion turbines shall not exceed a total of 2,240 turbine hours per twelve (12) consecutive month period with compliance determined at the end of each month.

(2) During periods of startup and shutdown, good combustion practices shall be used to limit NOx and CO emissions.

(3) The NOx and CO emissions during startup and shutdown periods shall be monitored.

(4) The startup and shutdown data for the first thirty-six (36) months of actual operation shall be submitted to the OAQ Permits Branch in order to evaluate and establish a short-term limit (pounds per startup and pounds per shutdown) during periods of startup and shutdown. The short-term limit shall consider, but will not be limited to, performance degradation of the combustion turbine up to the first major overhaul. The startup and shutdown data shall be submitted within 90 days after the 36-month monitoring period.

For the Auxiliary Boiler

Pursuant to CP #029-12517-00033, originally issued on June 7, 2001, and 326 IAC 2-2-3 (PSD BACT), the Permittee shall comply with the following requirements:

(a) Emissions from the auxiliary boiler shall not exceed the following emission limits:

Pollutant	Emission Limit (lbs/MMBtu)
PM/PM10	0.0081
NO_X	0.036
CO	0.082
SO_2	0.006
VOC	0.0054

(b) The natural gas usage in the auxiliary boiler shall not exceed 122.2 million standard cubic foot (MMSCF) per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) The Permittee shall operate the boiler with low-NOx burners.

(d) The Permittee shall use natural gas only for the auxiliary boiler.

(e) The sulfur content of the natural gas used shall not exceed 0.8% by weight.

(f) The Permittee shall perform good combustion practices for the auxiliary boiler.

For the Diesel Backup Electric Generator and the Diesel Fire Pump

Pursuant to CP #029-12517-00033, originally issued on June 7, 2001, and 326 IAC 2-2-3 (PSD BACT), the Permittee shall comply with the following requirements:

(a) The total fuel input to the diesel backup electric generator shall not exceed 35,252 gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

(b) The total fuel input to the diesel fire pump shall not exceed 7,554 gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) The sulfur content of the diesel fuel used shall not exceed 0.05% by weight.

(d) The Permittee shall use good combustion practices for these units.

For the Two (2) Cooling Towers

Pursuant to CP #029-12517-00033, originally issued on June 7, 2001, and 326 IAC 2-2-3 (PSD BACT), the Permittee shall comply with the following requirements:

(a) The total PM and PM10 emissions shall not exceed 0.876 lbs/hr for each cooling tower.

(b) The Permittee shall use good design and operation practices to limit the emissions from each cooling tower.

For the Startup Gas Heater GH1

Pursuant to Significant Modification #029-16235-00033, issued on December 23, 2002, and 326 IAC 2-2-3 (PSD BACT), the Permittee shall comply with the following requirements:

(a) The NOx emissions shall not exceed 0.14 lbs/MMBtu.

(b) The natural gas usage shall not exceed 5.3 million standard cubic feet (MMSCF) per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) Natural gas shall be the only fuel combusted by the gas heater GH1.

(d) The Permittee shall use good combustion practices.

(e) The opacity of the startup gas heater shall not exceed 20% (6-minute average), except for one 6-minute period per hour of not more than 27%. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

326 IAC 2-4.1 (Hazardous Air Pollutants)

This electric utility generating plant was constructed in 2001 and modified in 2003. Pursuant to CP #029-12517-00033, issued on June 7, 2001, and Minor Permit Revision #029-15867-00033, issued on August 30, 2002, the formaldehyde emissions from each of the combustion turbines (CT1, CT2, CT3, and CT4) shall not exceed 0.00013 lbs/MMBtu.

This is equivalent to 5.05 tons/yr of formaldehyde emissions from all four (4) combustion turbines [0.00013 lbs/MMBtu x (1,906.4 MMBtu/hr + 310 MMBtu/hr) x 8760 hr/yr x 1 ton/2000 lbs x 4 turbines = 5.05 tons/yr]. Combined with the HAP emissions from other existing source, the HAP emissions from the entire source are limited to less than 10 tons/yr for a single HAP and less than 25 tons for total HAPs. Therefore, the requirements of 326 IAC 2-4.1 are not applicable to this source.

326 IAC 1-5-2 (Emergency Reduction Plans)

The source submitted an Emergency Reduction Plan (ERP) on March 16, 2004.

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. Since the potential to emit PM10 of this source is greater than 250 tons/yr, the Permittee is required to submit an emission statement annually by July 1, pursuant to 326 IAC 2-6(a)(1). This statement must be received in accordance with the compliance schedule specified in 326 IAC 2-6-3 and must comply with the minimum requirements specified in 326 IAC 2-6-4. The submittal should cover the period identified in 326 IAC 2-6.

326 IAC 5-1 (Opacity Limitations)

This source is located in Lawrenceburg Township in Dearborn County. Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity for sources shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of thirty percent (30%) 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)

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).

State Rule Applicability – Combustion Turbines (CT1 through CT4)

326 IAC 6.5-1-2(a) (Particulate Matter Limitations Except Lake County)

This source is located in Dearborn County and is not specifically listed in 326 IAC 6.5-3 (formerly 326 IAC 6-1-8.1). Since turbines CT1 through CT4 are natural gas combustion units, the particulate emissions from turbines CT1 through CT4 are not subject to the requirements of 326 IAC 6.5 (Particulate Matter Limitations Except Lake County) pursuant to 326 IAC 6.5-1-1(b).

326 IAC 6-2 (Particulate Emissions Limitations for Sources of Indirect Heating)

The combustion turbines (CT1, CT2, CT3 and CT4) are not subject to the requirements of 326 IAC 6-2 because they are not sources of indirect heating.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)

The particulate emissions from the combustion turbines are subject to the requirements in 326 IAC 2-2-3 (PSD BACT). Therefore, these units are exempt from the requirements of 326 IAC 6-3, pursuant to 326 IAC 6-3-1(c)(1).

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)

The potential to emit SO_2 from each of the combustion turbines (CT1, CT2, CT3, and CT4) is greater than 25 tons/yr. Therefore, these units are subject to the requirements of 326 IAC 7-1. However, there are no specific SO_2 emission limitations in 326 IAC 7-1.1-2 for units combusting natural gas only. Pursuant to 326 IAC 7-2-1(c)(3), the Permittee shall submit reports of the calendar month average sulfur content, heat content, natural gas fuel consumption and SO_2 emission rate in pounds per MMBtu, upon request by IDEM, OAQ.

326 IAC 8-1-6 (New Facilities; General Reduction Requirements)

Each of the combustion turbines at this source was constructed after January 1, 1980 and has potential VOC emissions greater than 25 tons/yr. Therefore, the VOC emissions from these combustion turbines are subject to the requirements of 326 IAC 8-1-6 and are required to control the VOC emissions with the Best Available Control Technology (BACT). Pursuant to CP #029-12517-00033, issued on June 7, 2001, the BACT determined for 326 IAC 2-2 (PSD) satisfied the requirements of 326 IAC 8-1-6.

326 IAC 10-4 (NOx Budget Trading Program)

Pursuant to 326 IAC 10-4-2(16) each of combustion turbines at this source (CT1 through CT4) is considered an “electricity generating unit (EGU)” because it commenced operation after January 1, 1999, and serves a generator that has a nameplate capacity greater than twenty-five (25) megawatts that produces electricity for sale. Pursuant to 326 IAC 10-4-1(a)(1), an “EGU” is a NOx budget unit. Because this source meets the criteria of having one (1) or more NOx budget units, it is a NOx budget source. The Permittee shall be subject to the requirements of 326 IAC 10-4 (NOx

Budget Trading Program). The NOx budget permit is included in Section F of this Part 70 operating permit. The Technical Support Document for the NOx budget permit is provided as Appendix B to this Technical Support Document.

The requirements of 326 IAC 2-7-20(a) and (c) do not apply to emission trades of SO_2 or NOx in accordance with 326 IAC 21 or 326 IAC 10-4; therefore, no pre-notification of a trade under one of these rules is required.

State Rule Applicability – Heat Recovery Steam Generators (HRSG1 through HRSG4) with Duct Burners

326 IAC 6.5-1-2(a) (Particulate Matter Limitations Except Lake County)

This source is located in Dearborn County and is not specifically listed in 326 IAC 6.5-3 (formerly 326 IAC 6-1-8.1). Since the heat recovery steam generators are natural gas combustion units, the particulate emissions from these units are not subject to the requirements of 326 IAC 6.5 (Particulate Matter Limitations Except Lake County) pursuant to 326 IAC 6.5-1-1(b).

326 IAC 6-2 (Particulate Emissions Limitations for Sources of Indirect Heating)

Since the PM emissions from the heat recovery steam generators (HRSG1 through HRSG4) are subject to the requirements of 326 IAC 2-2-3 (PSD BACT), and 40 CFR 60, Subpart Da, the PM emissions from these units are exempt from the requirements of 326 IAC 6-2, pursuant to 326 IAC 6-2-1(e), (f) and (g).

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)

The particulate PM emissions from the heat recovery steam generators are subject to the requirements of 40 CFR 60, Subpart Da (326 IAC 12). Therefore, these units are exempt from the requirements of 326 IAC 6-3, pursuant to 326 IAC 6-3-1(c)(5).

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)

The potential to emit SO_2 from each of the heat recovery steam generators (HRSG1 through GRSG4) is less than 25 tons/yr. Therefore, these units are not subject to the requirements of 326 IAC 7-1.

326 IAC 8-1-6 (New Facilities; General Reduction Requirements)

Each of the heat recovery steam generators with duct burners (HRSG1 through GRSG4) at this source was constructed after January 1, 1980 and has potential VOC emissions less than 25 tons/yr. Therefore, the requirements of 326 IAC 8-1-6 (BACT) are not applicable to these units.

326 IAC 3-5 (Continuous Monitoring of Emissions)

The heat recovery steam generators with duct burners (HRSG1 through GRSG4) are subject to the requirements of 326 IAC 3-5 because they are fossil fuel-fired steam generators each with a heat input capacity greater than 100 MMBtu/hr, pursuant to 326 IAC 3-5-1(b)(2).

(a) Pursuant to 326 IAC 3-5-1(c)(2)(A)(i), an opacity monitor is not required because only gaseous fuel is combusted at these heat recovery steam generators.

(b) Pursuant to 326 IAC 3-5-1(c)(2)(B), an SO_2 continuous emission monitor (CEM) is not required because each steam generating unit and combustion turbine is not equipped with an SO_2 control device and 40 CFR 60 Subpart Da does not require an SO_2 monitor because only natural gas is combusted.

(c) Pursuant to 326 IAC 3-5-1(d) and CP #029-12517-00033, issued on June 7, 2001, the Permittee shall install, calibrate, certify, operate and maintain CO and NOx CEMs for each of the stacks S1, S2, S3, and S4 in accordance with 326 IAC 3-5-2 and 3-5-3.

(1) The continuous emission monitoring system (CEMS) shall measure NOx and CO emissions rates in pounds per hour and parts per million (ppmvd) corrected to 15% O_2. The use of CEMS to measure and record the NOx and CO hourly limits, is sufficient to demonstrate compliance with the limitations established in the

BACT analysis and set forth in the permit. To demonstrate compliance with the NOx limit, the source shall take an average of the ppmvd corrected to 15% O_2 over a three (3) hour averaging periods. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppm) corrected to 15% O_2 over a twenty four (24) hour period. The source shall maintain records of the parts per million and the pounds per hour.

(2) The Permittee shall maintain a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4. If revisions are made to the SOP, updates shall be submitted to IDEM, OAQ biennially.

(3) 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. The source shall also be required to maintain records of the amount of natural gas combusted per turbine on a monthly basis and the heat input capacity.

Compliance with these requirements shall determine continuous compliance with the NOx and CO emission limits established under the 326 IAC 2-2-3 (PSD BACT).

State Rule Applicability – Auxiliary Boiler

326 IAC 5-1-3 (Temporary Alternative Opacity Limitations)

Pursuant to 326 IAC 5-1-3 (a) (Temporary Alternative Opacity Limitations), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed the applicable 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 opacity limitation 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.

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

326 IAC 6.5-1-2(a) (Particulate Matter Limitations Except Lake County)

This source is located in Dearborn County and is not specifically listed in 326 IAC 6.5-3 (formerly 326 IAC 6-1-8.1). Since the auxiliary boiler is a natural gas combustion unit, the particulate emissions from this unit are not subject to the requirements of 326 IAC 6.5 (Particulate Matter Limitations Except Lake County) pursuant to 326 IAC 6.5-1-1(b).

326 IAC 6-2 (Particulate Emissions Limitations for Sources of Indirect Heating)

Since the PM emissions from the auxiliary boiler are subject to the requirements of 326 IAC 2-2-3 (PSD BACT), the PM emissions from these units are exempt from the requirements of 326 IAC 6-2, pursuant to 326 IAC 6-2-1(e) and (g).

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)

The PM emissions from the combustion turbines are subject to the requirements of in 326 IAC 2-2-3 (PSD BACT). Therefore, these units are exempt from the requirements of 326 IAC 6-3, pursuant to 326 IAC 6-3-1(c)(1).

326 IAC 8-1-6 (New Facilities; General Reduction Requirements)

The auxiliary boiler was constructed after January 1, 1980 and has potential VOC emissions less than 25 tons/yr. Therefore, the requirements of 326 IAC 8-1-6 (BACT) are not applicable to this boiler.

326 IAC 9-1-2 (Carbon Monoxide Emission Requirements)

This source is not among the listed source categories in 326 IAC 9-1-2. Therefore, the requirements of 326 IAC 9-1-2 are not applicable.

326 IAC 10-1 (Nitrogen Oxide Emission Requirements)
This source is not located in Clark or Floyd County. Therefore, the requirements of 326 IAC 10-1 are not applicable.

State Rule Applicability – Emergency Generators (Insignificant Activities)

326 IAC 6.5-1-2(a) (Particulate Matter Limitations Except Lake County)
This source is located in Dearborn County and is not specifically listed in 326 IAC 6.5-3 (formerly 326 IAC 6-1-8.1). The potential to emit PM of this source is greater than 100 tons/yr. Therefore, this source is subject to the requirements of 326 IAC 6.5-1-2 (formerly 326 IAC 6-1-2). Pursuant to 326 IAC 6.5-1-2(a), particulate matter (PM) from each of the emergency generators shall not exceed 0.03 grain per dry standard cubic foot (gr/dscf) of exhaust air.

326 IAC 9-1-2 (Carbon Monoxide Emission Requirements)
This source is not among the listed source categories in 326 IAC 9-1-2. Therefore, the requirements of 326 IAC 9-1-2 are not applicable.

326 IAC 10-1 (Nitrogen Oxide Emission Requirements)
This source is not located in Clark or Floyd County. Therefore, the requirements of 326 IAC 10-1 are not applicable.

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)
The diesel backup electric generator and diesel fire pump are not subject to the requirements of 326 IAC 7-1.1 because each of them has the potential to emit SO_2 less than 25 tons/yr.

State Rule Applicability – Cooling Towers (Insignificant Activities)

326 IAC 6.5-1-2(a) (Particulate Matter Limitations Except Lake County)
This source is located in Dearborn County and is not specifically listed in 326 IAC 6.5-3 (formerly 326 IAC 6-1-8.1). The potential to emit PM of this source is greater than 100 tons/yr. Therefore, this source is subject to the requirements of 326 IAC 6.5-1-2 (formerly 326 IAC 6-1-2). Pursuant to 326 IAC 6.5-1-2(a), particulate matter (PM) from each of the cooling towers shall not exceed 0.03 grain per dry standard cubic foot (gr/dscf) of exhaust air.

State Rule Applicability – Storage Tanks (Insignificant Activities)

326 IAC 8-9 (Volatile Organic Liquid Storage Vessels)
This source is not located in Clark, Floyd, Lake, or Porter County. Therefore, the requirements of 326 IAC 8-9 are not applicable to the storage tanks at this source.

326 8-4-3 (Petroleum Liquid Storage Facilities)
The fuel storage tanks at this source have capacities less than 39,000 gallons. Therefore, the requirements of 326 IAC 8-4-3 are not applicable to these tanks.

326 IAC 12 (NSPS Requirements)
All the storage tanks at this source have capacities less than 40 cubic meters (10,567 gallons). Therefore, the requirements of New Source Performance Standards for Volatile Organic Liquid Storage Vessels for which construction, reconstruction, or modification commenced after July 23, 1984 (326 IAC 12, 40 CFR 60.110b - 117b, Subpart Kb as of date July 1, 2002) are not applicable to the storage tanks at this source.

State Rule Applicability – Degreasing Operations (Insignificant Activities)

326 IAC 8-3-2 (Cold Cleaning Operations)
Any degreaser using VOC containing solvents is considered a cold cleaning operation. The degreasing operations at this source was constructed after January 1, 1980 and are subject to 326

IAC 8-3-2. Pursuant to 326 IAC 8-3-2, for cold cleaning operations constructed after January 1, 1980, the Permittee shall:

(a) Equip the cleaner with a cover;

(b) Equip the cleaner with a facility 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 manner that greater than twenty percent (20%) of the waste solvent (by weight) can evaporate into the atmosphere.

326 IAC 8-3-5 (Cold Cleaner Degreaser Operation and Control)

The degreasing operations, which use VOC containing solvents, were constructed after July 1, 1990 and do not have remote solvent reservoirs. Therefore, the degreasing operations at this source are subject to 326 IAC 8-3-5 and have the following requirements:

(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 facility 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 facility must be internal such that articles are enclosed under the cover while draining. The drainage facility 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°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 owner or operator of a cold cleaning facility construction of which commenced after July 1, 1990, 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.

Testing Requirements

During the time period of December 4 to December 15, 2003 and on January 5, 2004, the Permittee has conducted stack tests for turbine CT1 through CT4 and the auxiliary boiler to demonstrate that the emissions from these units are incompliance with all the applicable emission limits. In order to demonstrate continuous compliance with the PSD BACT limits, the Permittee shall perform the following tests every five (5) years:

(a) PM and PM10 tests for turbines CT1 through CT4 (stacks S1 through S4). Testing shall be conducted with and without the duct burners in operation.

Note that compliance with the NOx and CO emission limits for the combustion turbines are demonstrated using the NOx and CO CEMs data.

(b) NOx emission tests for the auxiliary boiler every five (5) years.

No stack testing are required for the backup electric generator, the diesel fired pump, and the startup heater GH1 because these units are insignificant activities and compliance with the BACT limits are demonstrated through keeping records of the fuel used. Operations of the high efficiency drift eliminators at all times will ensure compliance with PM/PM10 limit for the insignificant cooling towers. Therefore, no testing is required for the cooling towers.

Compliance Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with applicable state and federal rules on a more or less continuous basis. All state and federal rules contain compliance provisions, however, these provisions do not always fulfill the requirement for a more or less 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 requirements are divided into two sections: Compliance Determination Requirements and Compliance Monitoring Requirements.

Compliance Determination Requirements in Section D of the permit are those conditions that are found more or less directly within state and federal rules and the violation of which serves as grounds for enforcement action. If these conditions 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 approporiate corrective actions within a specific time period.

The compliance monitoring requirements applicable to this source are as follows:

1. The heat recovery steam generators (HRSG1 through HRSG4) and combustion turbines (CT1 through CT4) have applicable compliance monitoring conditions as specified below:

   (a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), and 326 IAC 2-2 (PSD), the Permittee is required to calibrate, certify, operate and maintain a continuous emission monitoring system (CEMS) for measuring NOx, CO, and O_2 emissions rates from the combustion turbine stacks (stacks S1 through S4) in accordance with 326 IAC 3-5 and 40 CFR 60 to demonstrate compliance with 326 IAC 2-2, and 326 IAC 3-5.

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

   (c) Pursuant to 326 IAC 3-5-4(a), if revisions are made to the continuous monitoring standard operating procedures (SOP), the Permittee shall submit updates to the department biennially.

   (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.

   (e) In instances of CO continuous emission monitoring system (CEMS) downtime, the Permittee shall use a data substitution procedure for CO that is consistent with the requirements of 40 CFR Part 75, Appendix D (Optional SO_2 Emissions Data Protocol) for fuel flow meters requirements, and 40 CFR Part 75, Appendix E (Optional NOx Emissions Estimation Protocol) for emission rate curve establishment. CO mass emissions reported shall be based on the fuel-and-unit-specific CO emission rates ("load curve") established during the latest stack test.

   These monitoring conditions are necessary to ensure compliance with 326 IAC 2-2, 326 IAC 3-5, 326 IAC 10-4, and 40 CFR 75.

   There are no specific compliance monitoring requirements for the natural gas fired auxiliary boiler under state rules.

Conclusion

The operation of this electric generating station shall be subject to the conditions of this Part 70 operating permit T029-18580-00033.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
Office of Air Quality

Technical Support Document (TSD) for the NO_X Budget Permit

Source Background and Description

Source Name:	**PSEG Lawrenceburg Energy Company, LLC**
Source Location:	**582 West Eads Parkway, Lawrenceburg, Indiana 47025**
County:	**Dearborn**
SIC Code:	**4911**
Operation Permit No.:	**T029-18580-00033 (draft)**
Operated By:	**PSEG Lawrenceburg Energy Company, LLC**
Owned By:	**PSEG Lawrenceburg Energy Company, LLC**
ORIS Code:	**55502**

NO_X Budget Permit Application and Rule Applicability

A complete Nitrogen Oxides (NO_X) Budget Permit Application for this NO_X budget source was received on June 23, 2004. The Office of Air Quality (OAQ) has reviewed a NO_X budget permit application from PSEG Lawrenceburg Energy Company, LLC under 326 IAC 10-4-7 for the operation of the NO_X budget source. The NO_X budget source includes all NO_X Budget Units at the source, including opt-in units, if applicable. The following units at the source are NO_X Budget Units:

Four (4) natural gas-fired combustion turbine generators, identified as units CT1, CT2, CT3, CT4, constructed in 2001, each with a maximum heat input capacity of 1,906.4 MMBtu/hr (higher heating value), controlled by low NOx burners and four (4) selective catalytic reduction (SRC) systems (SCR11, SCR12, SCR21 and SCR22), exhausting to stacks S1, S2, S3 and S4, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The total maximum power output is 1,130 megawatts (MW).

Pursuant to 326 IAC 10-4-2(16), units CT1, CT2, CT3, and CT4, are each considered an "electricity generating unit (EGU)" because they commenced operation on or after January 1, 1999 and each unit 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 NO_X budget permit is in Section F of the Part 70 permit.

The requirements of 326 IAC 2-7-20(a) and (c) do not apply to emission trades of SO_2 or NO_X in accordance with 326 IAC 21 or 326 IAC 10-4; therefore, no pre-notification of a trade under one of these rules is required.

Pursuant to 326 IAC 10-4-7, the NO_X budget permit shall be a complete and segregable portion of the Part 70 permit and the NO_X budget portion of the Part 70 permit shall be administered in accordance with 326 IAC 2-7, except as provided otherwise by 326 IAC 10-4-7.

Program Description

On October 27, 1998, the U.S. EPA promulgated final federal rules requiring 22 states and the District of Columbia to submit state implementation plan (SIP) revisions to reduce the regional transport of ozone. The federal rule focused on reducing NO_X emissions in the affected states. In the federal rule, the U.S. EPA established a NO_X emission "budget" for each of the affected states and the District of Columbia. The "budget" represents a reduction from emissions in the year 2007 that the U.S. EPA believes will reduce the transport of NO_X emissions and will assist downwind areas in meeting ozone air quality standards. The states must demonstrate compliance with the "budget" by implementing control measures to reduce NO_X emissions beginning May 31, 2004. While the rule does not mandate which sources will have to reduce emissions, the rule did provide options that would result in a 65% reduction of NO_X emissions from utility boilers and a 60% reduction from large industrial (non-utility) boilers and turbines. IDEM developed the NO_X Budget Trading Program in 326 IAC 10-4 in response to this mandate. The NO_X reductions that will be achieved by this rule will result in significant air quality improvements throughout the state of Indiana, and will be especially important in those areas of the state where ozone levels exceed or regularly approach state and federal air quality health standards.

The Nitrogen Oxides Budget Trading Program is a regional cap and trade program among all the states subject to the NO_X SIP call. Electricity generating units (EGUs) and non-electricity generating units (non-EGUs) are allocated allowances for tons of NO_X that they are allowed to emit during the ozone season. IDEM allocates NO_X allowances for the affected units, and owners or operators of these units are able to buy, sell, or trade allowances, as necessary, to demonstrate compliance with the unit's NO_X emissions cap. Because this program is a regional program administered by U.S. EPA, sources are able to buy, sell or trade allowances across state boundaries and between different types of units and sources. More information about the NO_X SIP Call can be found at: http://www.epa.gov/airmarkets/fednox/index.html and http://www.in.gov/idem/air/standard/Sip/index.html.

326 IAC 10-4 (NO_X Budget Trading Program) Requirements

(a) Pursuant to 326 IAC 10-4-4(b), the owners and operators 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. 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).

(b) Pursuant to 326 IAC 10-4-4(c), the owners and operators 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.

(c) Pursuant to 326 IAC 10-4-4(d), the owners and operators of each NO_X budget unit that has excess emissions in any ozone control period shall do the following:

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

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

(d) Pursuant to 326 IAC 10-4-4(e)(1), unless otherwise provided, the owners and operators 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 owners or operators with unattended sources, each of the following documents for a period of five (5) years:

(1) 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 owners or operators 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.

(2) 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.

(3) Copies of all reports, compliance certifications, and other submissions and all records made or required under the NO_X budget trading program.

(4) 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 the 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.

(e) Pursuant to 326 IAC 10-4-4(e)(2), 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.

Monitoring

The NO_X Budget Trading Program references monitoring and reporting requirements from the Acid Rain program at 40 CFR Part 75. These provisions require, for most sources, the use of continuous emissions monitors (CEMs). A CEM is a system composed of various equipment that continuously measures the amount of nitrogen oxides emitted into the atmosphere in exhaust gases from the NO_X budget unit's stack.

Excepted monitoring systems under 40 CFR Part 75, Appendix E are allowed for gas-fired peaking units and oil-fired peaking units as defined in 40 CFR 72.2. The excepted monitoring system methodology involves performing stack tests to determine the average NO_X emissions rate from a unit at four, equally-spaced load levels, in accordance with specific US EPA test methods, to establish a "load curve". The "load curve" correlates emissions to heat input rate such that emissions can be estimated based on the actual hourly heat input.

NO_x Emissions Allocations

(a) Pursuant to 326 IAC 10-4-7(e), this NO_X budget permit is deemed to incorporate automatically, 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 the compliance accounts of the NO_X budget units or the overdraft account of the NO_X budget source covered by this permit. The allocations for each ozone season and transaction information can be found at: http://www.epa.gov/airmarkets/tracking/factsheet.html. In addition, IDEM, OAQ posts proposed allocations prior to submitting them to the U.S. EPA on the following web site: http://www.in.gov/idem/air/standard/Sip/index.html.

(b) The following requirements from 326 IAC 10-4-4(c) apply to NO_X allowances:

(1) 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.

(2) 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.

(3) A NO_X allowance shall not be deducted, in order to comply with the requirements under 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.

(4) 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.

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

(6) 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 a 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.

Other Record Keeping and Reporting Requirements

Pursuant to 326 IAC 10-4-7(g), except as provided in 326 IAC 10-7-4(e), IDEM, OAQ shall revise the NO_X budget permit, as necessary, in accordance with the permit modification and revision provisions under 326 IAC 2-7.

Pursuant to 326 IAC 10-4-7(b)(1)(C), for permit renewal, the NO_X authorized account representative shall submit a complete NO_X budget permit application covering the NO_X budget units at the source in accordance with 326 IAC 2-7-4(a)(1)(D) with the Part 70 permit renewal.

Submissions

The NO_X authorized account representative for each NO_X budget source on behalf of which a submission is made must sign and certify every report or other submission required by the NO_X budget permit. The NO_X authorized account representative must include the following certification statement in every submission: "I am authorized to make this submission on behalf of the owners and operators 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."

Recommendation

The staff recommends to the Commissioner that the NO_X budget permit be approved.

Unless otherwise stated, information used in this review was derived from the application.

Additional Information

Questions regarding the NO_X budget permit can be directed to Madhurima Moulik at the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ), 100 North Senate Avenue, P.O. Box 6015, Indianapolis, Indiana 46206-6015 or by telephone at (317) 233-0868 or toll free at 1-800-451-6027 extension 3-0868.

The source will be inspected by IDEM's compliance inspection staff. Persons seeking to obtain information regarding the source's compliance status or to report any potential violation of any permit condition should contact Alexandra Yueng at the Office of Air Quality (OAQ) address or by telephone at (317) 233-0863 or toll free at 1-800-451-6027 extension 3-0863.

Copies of the Code of Federal Regulations (CFR) referenced in the permit may be obtained from:

Indiana Department of Environmental Management
Office of Air Quality
100 North Senate Avenue
P.O. Box 6015
Indianapolis, Indiana 46206-6015
or
The Government Printing Office
Washington, D.C. 20402
or
on the Government Printing Office web site at
http://www.access.gpo.gov/nara/cfr/index.html

Appendix A: Emission Calculations
Natural Gas Combustion
From Four (4) Combustion Turbines and the Associated Duct Burners

Company Name: PSEG Lawrenceburg Energy Facility
Address: 582 West Eads Parkway, Lawrenceburg, IN 47025
TV #: T029-18580-00033
Reviewer: ERG/YC
Date: January 4, 2006

Heat Input Capacity
(MMBtu/hr)

1,906	(without duct burner)
2,216	(with duct burner)

Pollutant

	PM	PM10	SO_2	NO_x	VOC	CO
*Emission Limit (lbs/hr) - without duct burner	21.0	21.0	11.0	21.0	3.00	21.3
*Emission Limit (lbs/hr) - with duct burner	24.1	24.1	12.71	24.41	7.70	40.5
Potential to Emit (tons/yr) for each Turbine	**106**	**106**	**55.7**	**107**	**33.7**	**177**
Potential to Emit (tons/yr) for 4 Turbines	**422**	**422**	**223**	**428**	**135**	**710**

* These are the emission limits established in CP #029-12517-00033, issued on June 7, 2001.

Methodology

PTE(tons/yr) for each turbine = Worst Case Emission Limit (lbs/hr) x 8760 hrs/yr x 1 ton/2000 lbs
PTE (tons/yr) for 4 Turbines = PTE (tons/yr) for each turbine x 4

Appendix A: Emission Calculations
HAP Emissions
From Four (4) Combustion Turbines (CT1 through CT4)

Company Name: PSEG Lawrenceburg Energy Facility
Address: 582 West Eads Parkway, Lawrenceburg, IN 47025
TV #: T029-18580-00033
Reviewer: ERG/YC
Date: January 4, 2006

Heat Input Capacity
MMBtu/hr

1,906.4 (each, without duct burner)

	Pollutant					
*Emission Factor in lbs/MMBtu	Formaldehyde** 1.30E-04	Toluene 1.30E-04	Xylene 6.40E-05	Acetaldehyde 4.00E-05	Ethylbenzene 3.20E-05	Total HAP
PTE (tons/yr) for each turbine	**1.09**	**1.09**	**0.53**	**0.33**	**0.27**	**3.31**
PTE (tons/yr) for 4 turbines	**4.34**	**4.34**	**2.14**	**1.34**	**1.07**	**13.2**

* Emission factors are from AP-42, Table 3.1-3 for NG fired gas turbines (AP-42, 04/00), except Formaldehyde.
** This is the emission limit established in Minor Permit Revision #029-15867-00033, issued on August 30, 2002.
This emission factor is lower than the one in AP-42, Table 3.1-3.

Methodology

PTE (tons/yr) for each turbine = Max. Heat Input (MMBtu/hr) x Emission Factor (lbs/MMBtu) x 8760 hr/yr x 1 ton/2000 lbs
PTE (tons/yr) for 4 Turbines = PTE (tons/yr) for each turbine x 4

Appendix A: Emission Calculations
HAP Emissions
From Four (4) Duct Burners with the Combustion Turbines (CT1 through CT4)

Company Name: PSEG Lawrenceburg Energy Facility
Address: 582 West Eads Parkway, Lawrenceburg, IN 47025
TV #: T029-18580-00033
Reviewer: ERG/YC
Date: January 4, 2006

Heat Input Capacity
MMBtu/hr

310 (each)

Pollutant

	Hexane	Formaldehyde	Toluene	Benzene	Nickel	
*Emission Factor in lbs/MMCF	1.8E+00	7.5E-02	3.4E-03	2.1E-03	2.1E-03	Total HAP
PTE (tons/yr) for each turbine	**2.44**	**0.10**	**4.62E-03**	**2.85E-03**	**2.85E-03**	**2.56**
PTE (tons/yr) for 4 turbines	**9.78**	**0.41**	**0.02**	**0.01**	**0.01**	**10.2**

*Emission factors are from AP-42, Chapter 1.4, Table 1.4-3 (AP-42, 03/98).

Methodology

PTE (tons/yr) for each turbine = Heat Input Capacity (MMBtu/hr) x 1 MMCF/1,000 MMBtu x Emission Factor (lbs/MMCF) x 8760 hr/yr x 1 ton/2000 lbs
PTE (tons/yr) for 4 Turbines = PTE (tons/yr) for each turbine x 4

Appendix A: Emission Calculations
Natural Gas Combustion
from the Auxiliary Boiler

Company Name: PSEG Lawrenceburg Energy Facility
Address: 582 West Eads Parkway, Lawrenceburg, IN 47025
TV #: T029-18580-00033
Reviewer: ERG/YC
Date: January 4, 2006

Heat Input Capacity MMBtu/hr	Max. NG Usage MMCF/yr
116.4	122.2

	Pollutant					
	PM	PM10	SO_2	NO_x	VOC	CO
*Emission Factor in lbs/MMBtu	0.0081	0.0081	0.006	0.036	0.0054	0.082
Potential to Emit in tons/yr	**0.49**	**0.49**	**0.37**	**2.20**	**0.33**	**5.01**

* These are the emission limits established in CP #029-12517-00033, issued on June 7, 2004.

Methodology

Potential to Emit (tons/yr) = Max. Fuel Usage (MMCF/yr) x 1,000 MMBtu/1 MMCF x Emission Factor (lbs/MMBtu) x 1 ton/2000 lbs

Appendix A: Emission Calculations
Internal Combustion Engines

From the Diesel Backup Electric Generator (Insignificant)

Company Name: PSEG Lawrenceburg Energy Facility
Address: 582 West Eads Parkway, Lawrenceburg, IN 47025
TV #: T029-18580-00033
Reviewer: ERG/YC
Date: January 4, 2006

Power Output Horse Power (HP)	Operation Limit (hr/yr)	S = Weight % Sulfur Limit***
1,341	500	0.05

Pollutant

	PM*	PM10*	SO_2	NO_x	**VOC	CO
Emission Factor in lb/HP-hr	7.00E-04	7.00E-04	4.05E-04 (8.09E-03*S)	2.40E-02	7.05E-04	5.50E-03
Potential to Emit in tons/yr	**0.23**	**0.23**	**0.14**	**8.05**	**0.24**	**1.84**

*Assume PM10 emissions are equal to PM emissions.
** Assume TOC (total organic compounds) emissions are equal to VOC emissions.
*** This sulfur content limit was established in CP #029-12517-00033, issued on June 7, 2004.
Emission factors are from AP-42, Table 3.4-1, SCC #2-02-004-01 (AP-42, 10/96).

Note: As defined in the September 6, 1995 memorandum from John S. Seitz of US EPA on the subject of "Calculating Potential to Emit for Emergency Generators", an emergency generator's sole function is to provide back-up power when power from the local utility is interrupted. The only circumstances under which an emergency generator would operate when utility power is available are during operator training or brief maintenance checks. The generator's potential to emit is based on an operating time of 500 hours per year as set forth in the EPA memo.

Methodology

PTE (tons/yr) = Power Output (HP) x Emission Factor (lb/HP-hr) x Operation Limit (hr/yr) x 1 ton/2000 lbs

Appendix A: Emission Calculations
Internal Combustion Engines

From the Diesel Fired Pump (Insignificant)

Company Name: PSEG Lawrenceburg Energy Facility
Address: 582 West Eads Parkway, Lawrenceburg, IN 47025
TV #: T029-18580-00033
Reviewer: ERG/YC
Date: January 4, 2006

Power Output Horse Power (HP)	Operation Limit (hr/yr)
265	500

Pollutant

	PM*	PM10*	SO_2	NO_x	**VOC	CO
Emission Factor in lb/HP-hr	2.20E-03	2.20E-03	2.05E-03	3.10E-02	2.47E-03	6.68E-03
Potential to Emit in tons/yr	**0.15**	**0.15**	**0.14**	**2.05**	**0.16**	**0.44**

*Assume PM10 emissions are equal to PM emissions.
** Assume TOC (total organic compounds) emissions are equal to VOC emissions.
Emission factors are from AP-42, Chapter 3.3, Table 3.3-1, SCC #2-02-001-02 and 2-03-001-01 (AP-42 Supplement B, 10/96).

Note: As defined in the September 6, 1995 memorandum from John S. Seitz of US EPA on the subject of "Calculating Potential to Emit for Emergency Generators", an emergency generator's sole function is to provide back-up power when power from the local utility is interrupted. The only circumstances under which an emergency generator would operate when utility power is available are during operator training or brief maintenance checks. The generator's potential to emit is based on an operating time of 500 hours per year as set forth in the EPA memo.

Methodology

PTE (tons/yr) = Power Output (HP) x Emission Factor (lb/HP-hr) x Operation Limit (hr/yr) x 1 ton/2000 lbs

Appendix A: Emission Calculations
PM/PM10 Emissions
From the Two (2) Cooling Towers (Insignificant)

Company Name: PSEG Lawrenceburg Energy Facility
Address: 582 West Eads Parkway, Lawrenceburg, IN 47025
TV #: T029-18580-00033
Reviewer: ERG/YC
Date: January 4, 2006

Process Description (for each unit):

Control Devices:	Drift Eliminator
Flow Rate:	140,000 gallons/min
Total Dissolved Solids (TDS):	2,500 ppmv
Drift Losses (% of cooling water):	0.0005% (provided by the vender)

1. Potential to Emit of Each Cooling Tower:

Assume all the PM emissions are equal to PM10 emissions.

Hourly PM/PM10 Emissions	= 14,000 gal/min x 8.34 lbs/gal x 60 min/hr x 2,500 ppmv /1,000,000 x 0.005% =	**0.876**	**lbs/hr/unit**
Annual PM/PM10 emissions	= 0.876 lbs/hr x 8760 hr/yr x 1 ton/2000 lbs =	**3.84**	**tons/yr/unit**

2. Potential to Emit of Two (2) Cooling Towers:

Total PM/PM10 (tons/yr)	= 3.84 tons/yr/unit x 2 =	**7.67**	**tons/yr**

Appendix A: Emission Calculations
Natural Gas Combustion
(MMBtu/hr < 100)
From 2.4 MMBtu/hr Startup Heater (GH1)

Company Name: PSEG Lawrenceburg Energy Facility
Address: 582 West Eads Parkway, Lawrenceburg, IN 47025
TV #: T029-18580-00033
Reviewer: ERG/YC
Date: January 4, 2006

Heat Input Capacity MMBtu/hr	Fuel Usage Limit** MMCF/yr
2.4	5.3

Pollutant

	PM*	PM10*	SO_2	NOx**	VOC	CO
Emission Factor**	7.6 (lbs/MMCF)	7.6 (lbs/MMCF)	0.6 (lbs/MMCF)	0.14 (lbs/MMBtu)	5.5 (lbs/MMCF)	84.0 (lbs/MMCF)
Potential to Emit in tons/yr	**0.02**	**0.02**	**1.59E-03**	**0.37**	**0.01**	**0.22**

*PM and PM10 emission factors are condensable and filterable PM10 combined.
** These are the limitations established in Significant Modification #029-16235-00033, issued on December 23, 2002.
Emission factors for PM, PM10, SO_2, VOC, and CO are from AP-42, Chapter 1.4, Tables 1.4-1, 1.4-2, and 1.4-3 (AP-42, 03/98).

Methodology

PTE of PM, PM10, SO_2, VOC, and CO (tons/yr) = Fuel Usage Limit (MMCF/yr) x Emission Factor (lbs/MMCF) x 1 tons/2000 lbs
PTE of NOx (tons/yr) = Fuel Usage Limit (MMCF/yr) x 1,000 MMBtu/MMCF x Emission Factor (lbs/MMBtu) x 1 tons/2000 lbs

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 46204-2251
(317) 232-8603
(800) 451-6027
www.IN.gov/idem

Appendix A

Phase II Acid Rain Permit

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
Office of Air Quality

Source Name:	PSEG Lawrenceburg Energy Facility
Source Locations:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Operated by:	PSEG Lawrenceburg Energy Company, LLC
ORIS Code:	55502

This permit is issued to the above operator under the provisions of 326 Indiana Administrative Code (IAC) 21 and 40 Code of Federal Regulations (CFR) 72, 40 CFR 75 through 40 CFR 78 and 58 Federal Register (FR) 3590, with conditions listed on the attached pages.

Operation Permit No.: AR 029-12561-000331	
Issued by: Original signed by Janet G. McCabe Paul Dubenetzky, Assistant Commissioner Office of Air Quality	Issuance Date: June 25, 2001 Expiration Date: June 25, 2006

Section E Title IV Operating Conditions

Facility Description [326 IAC 2-7-5(15)]: a 1,130 MW natural gas-fired combined cycle power plant consisting of:

(a) Four (4) natural gas-fired combustion turbine generators, designated as units 01, 02, 03, and 04, with a maximum heat input capacity of 1,901.7 MMBtu/hr (per unit on a higher heating value basis), exhausting through stacks designated as S1, S2, S3, and S4, respectively.

(b) Four (4) heat recovery steam generators, designated as units HRSG1, HRSG2, HRSG3, HRSG4 with duct burners, and a maximum rate heat input capacity of 310 MMBtu/hr (per unit on a higher heating value), exhausting to stacks designated as S1, S2, S3, and S4, respectively.

(c) Four (4) selective catalytic reduction systems, designated as units SCR11, SCR12, SCR21, SCR22 to control nitrogen oxide emissions from the combustion turbine.

(d) One (1) natural gas-fired auxiliary boiler, designated as Auxiliary Boiler, with a maximum heat input capacity of 124.6 MMBtu/hr (on a higher heating value basis), exhausting to stack S5.

E.1.1 Statutory and Regulatory Authority

In accordance with IC 13-17-3-4, IC 13-17-3-11, IC 13-17-8-1, and IC 13-17-8-2 as well as Title IV - Acid Deposition Control - Section 400 of the Clean Air Act, the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) issues this permit pursuant to 326 IAC 2 and 326 IAC 21.

E.1.2 Standard Permit Requirements [326 IAC 21]

(a) The designated representative of each affected source and each affected unit at the source has submitted a complete Acid Rain permit application in accordance with the deadlines in 40 CFR 72.30.

(b) The owners and operators of each affected source and each affected unit at the source shall operate the unit in compliance with this Acid Rain permit.

E.1.3 Monitoring Requirements [326 IAC 21]

(a) The owners and operators and, to the extent applicable, the designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR 75.

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

(c) The requirements of 40 CFR 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or emissions characteristics at the unit required by the Clean Air Act and any provisions of the operating permit for the source.

E.1.4 Sulfur Dioxide Requirements [326 IAC 21]

(a) The owners and operators of each source and each affected unit at the source shall:

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

(2) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

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

(c) An affected unit shall be subject to the requirements under paragraph (a) of the sulfur dioxide requirements as follows:

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

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

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

(e) These units were not allocated allowances by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR part 73. However, these units must still comply with the requirement to hold allowances to account for sulfur dioxide emissions under E.1.4(a) and 326 IAC 21.

(f) An allowance allocated by the U.S. EPA under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, the Acid Rain portion of an operating permit, or the written exemption under 40 CFR 72.7 and 72.8 and 326 IAC 21, and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. Pursuant to 40 CFR 72.9(c)(7), allowances allocated by U.S. EPA do not constitute a property right.

(f) These units have no sulfur dioxide (SO_2) allowance allocations from U.S. EPA. The allowances shall be obtained from other units to account for the SO_2 emissions from these units as required by 40 CFR 72.9(c).

E.1.5 Nitrogen Oxides Requirements [326 IAC 21]

Pursuant to 40 Code of Federal Regulations (CFR) 76, Acid Rain Nitrogen Oxides Emission Reduction Program, the units are not subject to the nitrogen oxide limitations set out in 40 CFR 76.

E.1.6 Excess Emissions Requirements for Sulfur Dioxide [326 IAC 21]

(a) The designated representative of an affected unit that has excess emissions of sulfur dioxide in any calendar year shall submit a proposed offset plan to U.S. EPA and IDEM, OAQ as required under 40 CFR 77 and 326 IAC 21.

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

Indiana Department of Environmental Management
Air Compliance Section I, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46204-2251-6015

and

Ms. Cecilia Mijares
Air and Radiation Division
U.S. Environmental Protection Agency, Region V
77 West Jackson Boulevard
Chicago, IL 60604-3590

and

U.S. Environmental Protection Agency

Acid Rain Program (6204J)
Attn.: Annual Reconciliation
401 M Street, SW
Washington, DC 20460

(c) The owners and operators of an affected unit that has excess emissions in any calendar year shall:

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

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

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

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

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

(2) All emissions monitoring information, in accordance with 40 CFR 75;

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

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

(b) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 72.90 subpart I, 40 CFR 75, and 326 IAC 21. Submit required information to the appropriate authority(ies) as specified in 40 CFR 72.90 subpart I and 40 CFR 75.

E.1.8 Submissions [326 IAC 21]

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

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

Indiana Department of Environmental Management
Permit Administration Section, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46204-2251

and

U.S. Environmental Protection Agency

Acid Rain Program (6204J)
Attn.: Designated Representative
401 M Street, SW
Washington, DC 20460

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

(d) In each submission under the Acid Rain Program, the designated representative shall certify, by his or her signature:

(1) The following statement, which shall be included verbatim in the submission: “I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made”; and

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

(e) The designated representative of a source shall notify each owner and operator of the source and of an affected unit at the source:

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

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

(3) Provided that the submission or determination covers the source or the unit.

(f) The designated representative of a source shall provide each owner and operator of an affected unit at the source a copy of any submission or determination under condition (d) of this section, unless the owner or operator expressly waives the right to receive a copy.

E.1.9 Severability [326 IAC 21]

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

E.1.10 Liability [326 IAC 21]

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

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

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

(d) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

(e) Any provision of the Acid Rain Program that applies to an affected source, including a provision applicable to the designated representative of an affected source, shall also apply to the owners and operators of such source and of the affected units at the source.

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

(g) Each violation of a provision of 40 CFR Parts 72, 73, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Clean Air Act.

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

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

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

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

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

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

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