INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

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

TO: Interested Parties / Applicant

DATE: August 19, 2011

RE: Whiting Clean Energy, Inc. / 089-29885-00449

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

Notice of Decision: Approval – Effective Immediately

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

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

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

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

The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

(1) the date the document is delivered to the Office of Environmental Adjudication (OEA);
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OEA by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OEA by private carrier.

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

(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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Part 70 Operating Permit Renewal
OFFICE OF AIR QUALITY

Whiting Clean Energy, Inc
2155 Standard Avenue
Whiting, Indiana 46394

(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.: T089-29885-00449	
Issued by: for Tripurari P. Sinha, Ph. D., Section Chief Permits Branch Office of Air Quality	Issuance Date: August 19, 2011 Expiration Date: August 19, 2016

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.3 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(15)][326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary industrial steam and 545 Mwe co-generation (Combined heat and power) Plant.

Source Address:	2155 Standard Avenue, Whiting, Indiana 46394
General Source Phone Number:	(219)-473-0653
SIC Code:	4911
County Location:	Lake
Source Location Status:	Nonattainment for PM2.5 standard Attainment for all other criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules 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) Two (2) Combined-cycle Combustion Turbines (CT), each constructed in 2001:

Make/Model:	General Electric Frame 7FA (Model 7241)
Heat Input Capacity (HIC):	1,735 MMBtu per hour (HHV) @ ISO conditions, each
Electric Generating Capacity:	166 MW @ ISO conditions, each
Fuel Source:	Natural Gas
Control Technology:	Dry Low-NO_x Burners
Stack ID:	CT1 exhausts through HRSG1 to stack 1 CT2 exhausts through HRSG2 to stack 2

(b) Two (2) Heat Recovery Steam Generators (HRSG), each with a Duct Burner set (DB), each constructed in 2001:

Steam Generating Capacity:	1300 psig
Duct Burner HIC:	821 MMBtu per hour (HHV), per set
Fuel Source:	Natural Gas
Control Technology:	Selective Catalytic Reduction (SCR) System for NOx control
Steam Production Capacity:	580,000 pounds per hour, each, without DBs 1,188,000 pounds per hour, each, with DBs

Stack ID:	DB1 exhausts to stack 1 DB2 exhausts to stack 2

(c) One (1) Condensing Steam Turbine Generator (CSTG), constructed in 2001:
Electric Generating Capacity: 213 MW @ 1,600,000 pounds per hour steam

(d) One (1) Induced Draft Non-Contact Cooling Tower, constructed in 2001:

System Technology:	5 cycle, 10 cell, induced draft cooling tower
Water Circulation Rate:	160,000 gallons per minute non-contact cooling water
Control Technology:	Drift Eliminator for particulate control
Stack ID:	Stacks C1 through C10

Note that the Condensing Steam Turbine Generator (CSTG) is not a source of emissions. It utilizes the steam produced from the Heat Recovery Steam Generators (HRSGs) to produce electricity. The CSTG has been included for clarity because it is a part of the entire source and operates in conjunction with the HRSGs and cooling tower (which is a source of emissions). As a result, the CSTG is not mentioned further in this document.

Also note that the Heat Recovery Steam Generators (HRSGs) 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 Burner Sets (which are a source of emissions). As a result, the HRSGs are not mentioned further in this document.

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

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

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

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

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

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

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

(c) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3);

SECTION B GENERAL CONDITIONS

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

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

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

(a) The Part 70 Operating permit, T089-29885-00449, is issued for a fixed term of five (5) years, 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.

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

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

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

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

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

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

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

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

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

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

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

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

(a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. Upon request, the Permittee shall also furnish to IDEM, OAQ copies of records required to be kept by this permit.

(b) For information furnished by the Permittee to IDEM, OAQ, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1. When furnishing copies of requested records directly to U. S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.

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

(a) A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:

(1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(34), and

(2) the certification states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) The Permittee may use the attached Certification Form, or its equivalent with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.

(c) A "responsible official" is defined at 326 IAC 2-7-1(34).

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

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. All certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than April 15 of each year to:

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

and

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

(b) The annual compliance certification report required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(c) The annual compliance certification report shall include the following:

(1) The appropriate identification of each term or condition of this permit that is the basis of the certification;

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

(4) The methods used for determining the compliance status of the source, currently and over the reporting period consistent with 326 IAC 2-7-5(3); and

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

The submittal by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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) A Preventive Maintenance Plan meets the requirements of 326 IAC 1-6-3 if it includes, at a minimum:

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

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

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

The Permittee shall implement the PMPs.

(b) If required by specific condition(s) in Section D of this permit where no PMP was previously required, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this permit or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:

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

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

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

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

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

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

The Permittee shall implement the PMPs.

(c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(d) To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

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

(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:

(1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, or Northwest Regional Office no later than four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or
Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)
Facsimile Number: 317-233-6865
Northwest Regional Office phone: (219) 757-0265; fax: (219) 757-0267.

(5) For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile to:

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

no later than two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-7-5(3)(C)(ii) and must contain the following:

(A) A description of the emergency;

(B) Any steps taken to mitigate the emissions; and

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4(c)(9) be revised in response to an emergency.

(f) Failure to notify IDEM, OAQ by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-7 and any other applicable rules.

(g) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(a) All terms and conditions of permits established prior to T089-29885-00449 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

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

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

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

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

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

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

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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.16 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

Request for renewal shall be submitted to:

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

(b) A timely renewal application is one that is:

(1) Submitted at least nine (9) months prior to the date of the expiration of this permit; and

(2) If the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

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

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

(a) Permit amendments and modifications are governed by the requirements of 326 IAC 2-7-11 or 326 IAC 2-7-12 whenever the Permittee seeks to amend or modify this permit.

(b) Pursuant to 326 IAC 2-7-11(b) and 326 IAC 2-7-12(a), administrative Part 70 operating permit amendments and permit modifications for purposes of the acid rain portion of a Part 70 permit shall be governed by regulations promulgated under Title IV of the Clean Air Act. [40 CFR 72]

(c) Any application requesting an amendment or modification of this permit shall be submitted to:

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

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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.18 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]

(a) No Part 70 permit revision or notice shall be required under any approved economic incentives, marketable Part 70 permits, emissions trading, and other similar programs or processes for changes that are provided for in a Part 70 permit.

(b) Notwithstanding 326 IAC 2-7-12(b)(1) and 326 IAC 2-7-12(c)(1), minor Part 70 permit modification procedures may be used for Part 70 modifications involving the use of economic incentives, marketable Part 70 permits, emissions trading, and other similar approaches to the extent that such minor Part 70 permit modification procedures are explicitly provided for in the applicable State Implementation Plan (SIP) or in applicable requirements promulgated or approved by the U.S. EPA.

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

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b),(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
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

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

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

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-7-20(b),(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 a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(b) Any application requesting a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new Permittee. The application shall be submitted to:

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

The application which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)][326 IAC 2-1.1-7]

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

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

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

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

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

C.1 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of twenty percent (20%) 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.

C.3 Incineration [326 IAC 4-2] [326 IAC 9-1-2]

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

C.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. The provisions of 326 IAC 1-7-1(3), 326 IAC 1-7-2, 326 IAC 1-7-3(c) and (d), 326 IAC 1-7-4, and 326 IAC 1-7-5(a), (b), and (d) are not federally enforceable.

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

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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 Licensed Asbestos Inspector
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Licensed Asbestos Inspector to thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Licensed Asbestos inspector is not federally enforceable.

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

C.7 Performance Testing [326 IAC 3-6]

(a) For performance testing required by this permit, a test protocol, except as provided elsewhere in this permit, shall be submitted to:

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

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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 a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(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, for all monitoring requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or of initial start-up, whichever is later, to begin such monitoring. If due to circumstances beyond the Permittee's control, any monitoring equipment required by this permit cannot be installed and operated no later than ninety (90) days after permit issuance or the date of initial startup, whichever is later, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

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

in writing, prior to the end of the initial ninety (90) day compliance schedule, with full justification of the reasons for the inability to meet this date.

The notification which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

(a) When required by any condition of this permit, an analog instrument used to measure a parameter related to the operation of an air pollution control device shall have a scale such that the expected maximum reading for the normal range shall be no less than twenty percent (20%) of full scale.

(b) The Permittee may request that the IDEM, OAQ approve the use of an instrument that does not meet the above specifications provided the Permittee can demonstrate that an alternative instrument specification will adequately ensure compliance with permit conditions requiring the measurement of the parameters.

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

C.11 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

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

(a) The Permittee shall maintain the most recently submitted written emergency reduction plans (ERPs) consistent with safe operating procedures.

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

C.12 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.13 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]

Upon detecting an excursion where a response step is required by the D Section or an exceedance of a limitation in this permit:

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

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

(1) initial inspection and evaluation;

(2) recording that operations returned or are returning to normal without operator action (such as through response by a computerized distribution control system); or

(3) any necessary follow-up actions to return operation to normal or usual manner of operation.

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

(1) monitoring results;

(2) review of operation and maintenance procedures and records; and/or

(3) inspection of the control device, associated capture system, and the process.

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

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

C.14 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall submit a description of its response actions to IDEM, OAQ, no later than seventy-five (75) days after the date of the test.

(b) A retest to demonstrate compliance shall be performed no later than one hundred eighty (180) days after the date of the test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred eighty (180) days is not practicable, IDEM, OAQ may extend the retesting deadline

(c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

C.15 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) In accordance with the compliance schedule specified in 326 IAC 2-6-3(b)(1), the Permittee shall submit by July 1 an emission statement covering the previous calendar year as follows:

(1) starting in 2004 and every three (3) years thereafter, and

(2) any year not already required under (1) if the source emits volatile organic compounds or oxides of nitrogen into the ambient air at levels equal to or greater than twenty-five (25) tons during the previous calendar year.

(b) The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

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

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(32) (“Regulated pollutant, which is used only for purposes of Section 19 of this rule”) from the source, for purpose of fee assessment.

The statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue
MC 61-50 IGCN 1003
Indianapolis, Indiana 46204-2251

The emission statement does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

C.16 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, for all record keeping requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or the date of initial start-up, whichever is later, to begin such record keeping.

(c) If there is a reasonable possibility (as defined in 40 CFR 51.165(a)(6)(vi)(A), 40 CFR 51.165(a)(6)(vi)(B), 40 CFR 51.166(r)(6)(vi)(a), and/or 40 CFR 51.166(r)(6)(vi)(b)) that a “project” (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(ll)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a “major modification” (as defined in 326 IAC 2-2-1(ee) and/or 326 IAC 2-3-1(z)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(rr) and/or 326 IAC 2-3-1(mm)), the Permittee shall comply with the 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.

(d) If there is a reasonable possibility (as defined in 40 CFR 51.165(a)(6)(vi)(A) and/or 40 CFR 51.166(r)(6)(vi)(a)) that a “project” (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(ll)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a “major modification” (as defined in 326 IAC 2-2-1(ee) and/or 326 IAC 2-3-1(z)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(rr) and/or 326 IAC 2-3-1(mm)), the Permittee shall comply with following:

(1) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (1)(B) above; and

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

C.17 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

(b) The address for report submittal is:

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

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(d) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit “calendar year” means the twelve (12) month period from January 1 to December 31 inclusive.

(e) If the Permittee is required to comply with the recordkeeping provisions of (d) in Section C - General Record Keeping Requirements for any “project” (as defined in 326 IAC 2-2-1 (qq) and/or 326 IAC 2-3-1 (ll)) at an existing emissions unit, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:

(1) The annual emissions, in tons per year, from the project identified in (c)(1) in Section C- General Record Keeping Requirements exceed the baseline actual emissions, as documented and maintained under Section C- General Record Keeping Requirements (c)(1)(C)(i), by a significant amount, as defined in 326 IAC 2-2-1 (xx) and/or 326 IAC 2-3-1 (qq), for that regulated NSR pollutant, and

(2) The emissions differ from the preconstruction projection as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(ii).

(f) The report for project at an existing emissions unit shall be submitted no later than sixty (60) days after the end of the year and contain the following:

(1) The name, address, and telephone number of the major stationary source.

(2) The annual emissions calculated in accordance with (d)(1) and (2) in Section C - General Record Keeping Requirements.

(3) The emissions calculated under the actual-to-projected actual test stated in 326 IAC 2-2-2(d)(3) and/or 326 IAC 2-3-2(c)(3).

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

Reports required in this part shall be submitted to:

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

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

Stratospheric Ozone Protection

C.18 Compliance with 40 CFR 82 and 326 IAC 22-1

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

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) Two (2) Combined-cycle Combustion Turbines (CT), each constructed in 2001:

Make/Model:	General Electric Frame 7FA (Model 7241)
Heat Input Capacity (HIC):	1,735 MMBtu per hour (HHV) @ ISO conditions, each
Electric Generating Capacity:	166 MW @ ISO conditions, each
Fuel Source:	Natural Gas
Control Technology:	Dry Low-NO_x Burners
Stack ID:	CT1 exhausts through HRSG1 to stack 1 CT2 exhausts through HRSG2 to stack 2

(b) Two (2) Heat Recovery Steam Generators (HRSG), each with a Duct Burner set (DB), each constructed in 2001:

Steam Generating Capacity:	1300 psig
Duct Burner HIC:	821 MMBtu per hour (HHV), per set
Fuel Source:	Natural Gas
Control Technology:	Selective Catalytic Reduction (SCR) System for NOx control
Steam Production Capacity:	580,000 pounds per hour, each, without DBs 1,188,000 pounds per hour, each, with DBs
Stack ID:	DB1 exhausts to stack 1 DB2 exhausts to stack 2

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

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

D.1.1 PSD Particulate (PM and PM_{10}) Emission and Opacity Limitations [326 IAC 2-2-3]

(a) Pursuant to PSD/CP 089-11194-00449, issued July 20, 2000, and 326 IAC 2-2-3:

(1) The PM emissions from each combustion turbine stack (stacks 1 and 2), when only the respective turbine is operating, shall not exceed 0.0045 pounds per MMBtu (equivalent to less than or equal to 7.8 pounds per hour).

(2) The PM emissions from each combustion turbine stack (stacks 1 and 2), when the turbine and its associated duct burner set (DB1 and DB2) is operating, shall not exceed 0.0045 pounds per MMBtu (equivalent to less than or equal to 11.5 pounds per hour).

(3) The opacity from each combustion turbine stack (stacks 1 and 2) shall not exceed twenty percent (20%) in a 6-minute average, except for one 6-minute period per hour of not more than 27 percent. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction. Compliance with this limit will satisfy the requirements of 326 IAC 5-1 (Condition C.1).

(b) Pursuant to PSD/CP 089-11194-00449, issued July 20, 2000:

(1) The opacity from each combustion turbine stack (stacks 1 and 2) shall not exceed twenty percent (20%) in a 6-minute average, except for one 6-minute period per hour of not more than 27 percent. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

(2) The PM_{10} (filterable + condensible) emissions from each combustion turbine stack (stacks 1 and 2) shall not exceed 11.5 pounds per hour when its associated duct burner set (DB1 and DB2) is operating.

D.1.2 Particulate Matter Limitations for Lake County [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2(a) and 326 IAC 6.8-1-2(b)(3):

(1) When only the respective turbine is operating, the particulate matter emissions from each combustion turbine stack (stacks 1 and 2) shall not exceed 0.03 grains per dry standard cubic foot (gr/dscf).

(2) When its associated duct burner set is operating, the particulate matter emissions from each combustion turbine stack (stacks 1 and 2) shall not exceed 0.01 grains per dry standard cubic foot (gr/dscf).

D.1.3 Volatile Organic Compound (VOC) [326 IAC 2-2][326 IAC 8-1-6]

Pursuant to PSD/CP 089-11194-00449, issued July 20, 2000, 326 IAC 2-2 and 326 IAC 8-1-6:

(a) When only the respective turbine is operating, the VOC emissions from each combustion turbine stack (stacks 1 and 2), shall not exceed 0.0016 pounds per MMBtu (equivalent to less than or equal to 2.8 pounds VOC per hour).

(b) The VOC emissions from each combustion turbine stack (stacks 1 and 2), when its associated duct burner set (DB1 and DB2) is operating, shall not exceed 0.0046 pounds per MMBtu (equivalent to less than or equal to 11.8 pounds VOC per hour).

(c) Good combustion practices shall be implemented to minimize VOC emissions from the combustion turbines (CT1 and CT2) and duct burner sets (DB1 and DB2).

D.1.4 PSD Nitrogen Oxides (NO_x) Emission Limitations [326 IAC 2-2-3]

Pursuant to PSD/CP 089-11194-00449, issued July 20, 2000 and 326 IAC 2-2-3:

(a) During normal operation, the NO_x emissions from each combustion turbine stack (stacks 1 and 2), when only the respective turbine is operating, shall not exceed 3.0 ppmvd at 15 percent oxygen, based on a 3-hour rolling average (which is equivalent to less than or equal to 19.5 pounds NO_x per hour at ISO conditions).

(b) During normal operation, the NO_x emissions from each combustion turbine stack (stacks 1 and 2), when the turbine and its associated duct burner is operating, shall not exceed 3.0 ppmvd at 15 percent oxygen, based on a 3-hour rolling average (equivalent to less than or equal to 38.0 pounds NO_x per hour at ISO conditions).

(c) The duct burners shall not be operated until normal operation begins.

(d) Each combustion turbine shall be equipped with dry low-NO_x burners and operated using good combustion practices to control NO_x emissions.

(e) A selective catalytic reduction (SCR) system shall be operated at all times, except during periods of startup/shutdown, to control NO_x emissions.

(f) The annual emissions from the combustion turbines (CT1 and CT2) and duct burner sets (DB1 and DB2), including emissions from startup and shutdown operations, shall not exceed 262 tons of NO_x per twelve consecutive month period with compliance determined at the end of each month.

D.1.5 PSD Carbon Monoxide (CO) Emission Limitations [326 IAC 2-2-3]

Pursuant to PSD/CP 089-11194-00449, issued July 20, 2000, and 326 IAC 2-2-3:

(a) During normal operation, the CO emissions from each combustion turbine stack (stacks 1 and 2), when only the respective turbine is operating, shall not exceed 0.016 pounds per MMBtu (equivalent to less than or equal to 28.0 pounds of CO per hour).

(b) During normal operation, the CO emissions from each combustion turbine stack (stacks 1 and 2), when the turbine and its associated duct burner is operating, shall not exceed 0.037 pounds per MMBtu (equivalent to less than or equal to 93.7 pounds of CO per hour).

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

(d) The annual emissions from the combustion turbines (CT1 and CT2) and duct burner sets (DB1 and DB2), including emissions from startup and shutdown operations, shall not exceed 571 tons of CO per twelve consecutive month period with compliance determined at the end of each month.

D.1.6 Operation Limitations [326 IAC 2-2-3]

Pursuant to PSD/CP 089-11194-00449, issued July 20, 2000:

(a) The combined natural gas fuel usage from the duct burner sets (DB1 and DB2) shall not exceed 8,052 million standard cubic feet (MMSCF) per twelve consecutive month period with compliance determined at the end of each month.

Compliance with this limit, the PM_{10} emissions from the combustion turbines and the controlled PM_{10} emissions from the cooling tower is equivalent to source-wide PM_{10} emissions of less than 100 tons per year and will render the requirements of 326 IAC 2-2 not applicable with respect to PM_{10}.

(b) Each combustion turbine (CT1 and CT2) shall not exceed an heat input rate of 1735 MMBtu per hour (based on HHV at ISO conditions), determined on a 30-day rolling average basis. The averaging time shall only account for those periods that the respective combustion turbine is in operation.

D.1.7 Hazardous Air Pollutant (HAP) Emission Limitations [326 IAC 2-4.1][40 CFR 63, Subpart YYYY]

Pursuant to CP 089-11194-00449, issued July 20, 2000:

(a) The formaldehyde emissions from the combustion turbine stacks (stacks 1 and 2) shall not exceed 0.0005 pounds per MMBtu and less than 10 tons per year.

(b) The hexane emissions from the combustion turbine stacks (stacks 1 and 2) shall not exceed 0.0005 pounds per MMBtu and less than 10 tons per year.

Compliance with these limits and Condition D.1.6(a) will limit the source wide single HAP emissions to less than 10 tons per year and source wide combination of HAPs emission to less than 25 tons per year and render the requirements of 326 IAC 2-4.1 and 40 CFR 63, Subpart YYYY not applicable to these emission units.

D.1.8 PSD Air Quality Analysis Ammonia Limitations [326 IAC 2-2-4]

Pursuant to PSD/CP 089-11194-00449, issued July 20, 2000, and 326 IAC 2-2-4, in order to ensure that the ammonia emissions from the turbine exhausts do not contribute to a degradation of air quality, the ammonia emissions from each combustion turbine stack (stacks 1 and 2) shall not exceed 10 ppm.

D.1.9 Startup and Shutdown Limitations [326 IAC 2-2-3]

Pursuant to PSD/CP 089-11194-00449, issued July 20, 2000, 326 IAC 2-2-3, each combustion turbine (CT1 and CT2) shall comply with the following startup and shutdown limitations:

(a) A startup is defined as the operation in the period of time from the initiation of combustion until either: the turbine reaches a minimum load of seventy percent (70%), or the instantaneous outlet SCR NO_x concentration reaches a level less than 3.0 ppmvd at 15% O_2 for a period of 5 minutes, whichever occurs earlier.

(b) A shutdown is defined as operation at less than fifty percent (50%) load and descending to flame out.

(c) A startup or shutdown period shall not exceed four (4) hours. Each turbine shall not exceed 473 hours per year for startups and 260 hours per year for shutdowns with compliance demonstrated at the end of each month.

(d) The NO_x emissions from each combustion turbine stack (stacks 1 and 2) shall not exceed 510 pounds per startup and 49 pounds per shutdown. Each combustion turbine shall not exceed 41.5 tons of NO_x per year of startup and shutdown emissions.

(e) The CO emissions from each combustion turbine stack (stacks 1 and 2) shall not exceed 1,571 pounds per startup, and 220 pounds per shutdown. Each combustion turbine (CT1 and CT2) shall not exceed 168.7 tons per year of startup and shutdown emissions.

D.1.10 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

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

Compliance Determination Requirements

D.1.11 Testing Requirements [326 IAC 2-7-6(1),(6)][326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.1.1, the Permittee shall perform PM, PM_{10}, and PM2.5 and opacity testing utilizing methods approved by the Commissioner. This test shall be performed on one combustion turbine at maximum load, shall be repeated on alternating combustion turbines. This test shall be repeated at least once every five (5) years from the date of this valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition. EPA Method 9 opacity tests shall be performed concurrently with the PM, PM10, and PM2.5 compliance tests, unless meteorological conditions require rescheduling the opacity tests to another date.

(b) In order to demonstrate compliance with Condition D.1.3, the Permittee shall perform VOC testing utilizing methods approved by the Commissioner. This test shall be performed on one combustion turbine at maximum load, shall be repeated on alternating combustion turbines. This test shall be repeated at least once every five (5) years from the date of this valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

(c) In order to demonstrate compliance with Condition D.1.7, in the event significant adjustments are made to any of the burners or in the event any burners are replaced with a different type of burner, the Permittee shall perform hexane and formaldehyde testing no later than 90 days after resuming operations after such adjustment or replacement, utilizing methods approved by the Commissioner. When required due to a significant adjustment to any burner or a replacement of any burner with a different burner type, the testing shall be performed on one affected combustion turbine at maximum load, when its associated duct burners are in operation, and shall be repeated on alternating affected combustion turbine/duct burner sets. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

(d) In order to demonstrate compliance with Condition D.1.8, the Permittee shall perform ammonia testing utilizing methods approved by the Commissioner. This test shall be performed on one combustion turbine at maximum load, shall be repeated on alternating combustion turbines. This test shall be repeated at least once every five (5) years from the date of this valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

(e) The Permittee shall also complete the testing required by conditions (a), (b), (c) and (d) above for the respective combustion turbine (at maximum load) when its associated duct burner is in operation.

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

D.1.12 Continuous Emission Monitoring System (CEMS) [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5-1(b)(1), (b)(2) and (d)(1), and in order to comply with 326 IAC 2-2, the Permittee is required to calibrate, certify, operate and maintain a continuous emission monitoring system (CEMS) for measuring O_2, NO_x and CO emissions rates from the combustion turbine stacks (stacks 1 and 2) in accordance with 326 IAC 3-5 and 40 CFR Part 60 to demonstrate compliance with Conditions D.1.5, and D.1.9.

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

(c) In instances of CEMS downtime, the Permittee shall report the NO_x mass emissions in accordance with the procedures regulated by 40 CFR Part 75, Appendix D (Optional SO_2 Emissions Data Protocol) for fuel flow meters requirements, 40 CFR Part 75, Appendix E (Optional NO_x Emissions Estimation Protocol) for emission rate curve establishment, and Appendix G (Determination of CO_2 Emissions). NO_x mass emissions reported shall be based on the fuel-and-unit-specific NO_x emission rates ("load curve") established during the latest and most representative CEMS data.

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

D.1.13 Record Keeping Requirements

(a) To document the compliance status with Conditions D.1.6, the Permittee shall record the:

(1) Hourly natural gas flowrate to each combustion turbine and duct burner; and

(2) Heat input rate of each combustion turbine.

(b) To document the compliance status with Conditions D.1.4, D.1.5, and D.1.9, the Permittee shall maintain records of all CEMS data as required under 326 IAC 3-5-6 at the source in a manner so that they may be inspected by the IDEM, OAQ, or the U.S. EPA, if so requested or required. Records necessary to demonstrate compliance shall be available within 30 days of the end of each compliance period.

(c) To document the compliance status with Condition D.1.9, the Permittee shall maintain records of the following:

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

(2) The duration of all startup and shutdown events and total hours of startup and shutdown.

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

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

D.1.14 Reporting Requirements

(a) An excess emissions report based on the continuous emissions monitor system (CEMS) data for NO_x and CO pursuant to 326 IAC 3-5-7. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C - General Reporting Requirements of this permit. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(b) A quarterly summary of the information to document the compliance status with Conditions D.1.4(f), D.1.5(d), D.1.6(a) and D.1.9 shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

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

(1) Date of downtime.

(2) Time of commencement.

(3) Duration of each downtime.

(4) Reasons for each downtime.

(5) Nature of system repairs and adjustments.

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

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) One (1) Induced Draft Non-Contact Cooling Tower, constructed in 2001:

System Technology:	5 cycle, 10 cell, induced draft cooling tower
Water Circulation Rate:	160,000 gallons per minute non-contact cooling water
Control Technology:	Drift Eliminator for particulate control
Stack ID:	Stacks C1 through C10

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

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

D.2.1 Particulate Matter (PM) [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2(a), the particulate matter (PM) emissions from the cooling tower shall not exceed 0.03 grains per dry standard cubic foot (dscf).

Compliance Determination Requirements

D.2.2 Particulate Control

The Permittee shall use the drift eliminator to control particulate emissions at all times the cooling tower is in operation.

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Specifically Regulated Insignificant Activities

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

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

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

D.3.1 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.3.2 Volatile Organic Compounds (VOC) [326 IAC 8-3-5]

(a) Pursuant to 326 IAC 8-3-5(a) (Cold Cleaner Degreaser Operation and Control), the Permittee of a cold cleaner degreaser facility, construction of which commenced after July 1, 1990, shall ensure that the following 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 the solvent 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.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) Two (2) Combined-cycle Combustion Turbines (CT), each constructed in 2001:

Make/Model:	General Electric Frame 7FA (Model 7241)
Heat Input Capacity (HIC):	1,735 MMBtu per hour (HHV) @ ISO conditions, each
Electric Generating Capacity:	166 MW @ ISO conditions, each
Fuel Source:	Natural Gas
Control Technology:	Dry Low-NO_x Burners
Stack ID:	CT1 exhausts through HRSG1 to stack 1 CT2 exhausts through HRSG2 to stack 2

(b) Two (2) Heat Recovery Steam Generators (HRSG), each with a Duct Burner set (DB), each constructed in 2001:

Steam Generating Capacity:	1300 psig
Duct Burner HIC:	821 MMBtu per hour (HHV), per set
Fuel Source:	Natural Gas
Control Technology:	Selective Catalytic Reduction (SCR) System for NOx control
Steam Production Capacity:	580,000 pounds per hour, each, without DBs 1,188,000 pounds per hour, each, with DBs
Stack ID:	DB1 exhausts to stack 1 DB2 exhausts to stack 2

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

Acid Rain Program

E.1.1 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 for this source and any other applicable requirements contained in 40 CFR 72 through 40 CFR 78. The Acid Rain Permit is incorporated by reference into this permit.

E.1.2 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 E.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(b) Two (2) Heat Recovery Steam Generators (HRSG), each with a Duct Burner set (DB), each constructed in 2001:

Steam Generating Capacity:	1300 psig
Duct Burner HIC:	821 MMBtu per hour (HHV), per set
Fuel Source:	Natural Gas
Control Technology:	Selective Catalytic Reduction (SCR) System for NOx control
Steam Production Capacity:	580,000 pounds per hour, each, without DBs 1,188,000 pounds per hour, each, with DBs
Stack ID:	DB1 exhausts to stack 1 DB2 exhausts to stack 2

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

New Source Performance Standards (NSPS) Requirements [40 CFR 60]

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

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 and the two (2) duct burners associated with the heat recovery steam generators HRSG1 and HRSG2, except as otherwise specified in 40 CFR Part 60, Subpart Da.

E.2.2 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 two (2) duct burners associated with the heat recovery steam generators HRSG1 and HRSG2 as specified as follows:

(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)(1)
(13) 40 CFR 60.48Da(g)(3)
(14) 40 CFR 60.48Da(h)
(15) 40 CFR 60.48Da(i)
(16) 40 CFR 60.48Da(k)(2)(iv)
(17) 40 CFR 60.49Da(a)(2)(ii)
(18) 40 CFR 60.49Da(a)(3)
(19) 40 CFR 60.49Da(o)
(20) 40 CFR 60.50Da(a)
(21) 40 CFR 60.50Da(b)
(22) 40 CFR 60.50Da(c)(4)
(23) 40 CFR 60.50Da(d)
(24) 40 CFR 60.50Da(f)
(25) 40 CFR 60.51Da(a)
(26) 40 CFR 60.51Da(b)
(27) 40 CFR 60.51Da(c)
(28) 40 CFR 60.51Da(f)
(29) 40 CFR 60.51Da(h)
(30) 40 CFR 60.51Da(i)
(31) 40 CFR 60.51Da(j)
(32) 40 CFR 60.52Da(b)

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) Two (2) Combined-cycle Combustion Turbines (CT), each constructed in 2001:

Make/Model:	General Electric Frame 7FA (Model 7241)
Heat Input Capacity (HIC):	1,735 MMBtu per hour (HHV) @ ISO conditions, each
Electric Generating Capacity:	166 MW @ ISO conditions, each
Fuel Source:	Natural Gas
Control Technology:	Dry Low-NO_x Burners
Stack ID:	CT1 exhausts through HRSG1 to stack 1 CT2 exhausts through HRSG2 to stack 2

(b) Two (2) Heat Recovery Steam Generators (HRSG), each with a Duct Burner set (DB), each constructed in 2001:

Steam Generating Capacity:	1300 psig
Duct Burner HIC:	821 MMBtu per hour (HHV), per set
Fuel Source:	Natural Gas
Control Technology:	Selective Catalytic Reduction (SCR) System for NOx control
Steam Production Capacity:	580,000 pounds per hour, each, without DBs 1,188,000 pounds per hour, each, with DBs
Stack ID:	DB1 exhausts to stack 1 DB2 exhausts to stack 2

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

New Source Performance Standards (NSPS) Requirements [40 CFR 60]

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

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the two (2) natural gas combustion turbines CT1 and CT2 and two (2) duct burners associated with the heat recovery steam generators HRSG1 through HRSG2, except as otherwise specified in 40 CFR Part 60, Subparts GG.

E.3.2 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 two (2) natural gas combustion turbines CT1 and CT2 and two (2) duct burners associated with the heat recovery steam generators HRSG1 through HRSG2as specified as follows:

(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(a)(4)
(6) 40 CFR 60.332(b)
(7) 40 CFR 60.333
(8) 40 CFR 60.334(c)
(9) 40 CFR 60.334(h)(3)(i)
(10) 40 CFR 60.334(j)(1)(iii)
(11) 40 CFR 60.334(j)(5)
(12) 40 CFR 60.335(a)
(13) 40 CFR 60.335(b)(3)
(14) 40 CFR 60.335(b)(7).

SECTION F RESERVED

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

ORIS Code: 55259

Emissions Unit Description:

(a) Two (2) Combined-cycle Combustion Turbines (CT), each constructed in 2001:

Make/Model:	General Electric Frame 7FA (Model 7241)
Heat Input Capacity (HIC):	1,735 MMBtu per hour (HHV) @ ISO conditions, each
Electric Generating Capacity:	166 MW @ ISO conditions, each
Fuel Source:	Natural Gas
Control Technology:	Dry Low-NO_x Burners
Stack ID:	CT1 exhausts through HRSG1 to stack 1 CT2 exhausts through HRSG2 to stack 2

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

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

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

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

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

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

(b) The CAIR NO_X unit(s), CAIR SO_2 unit(s), and CAIR NO_X ozone season unit(s) subject to this CAIR permit are CT1 and CT2.

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

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

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

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

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

(b) A CAIR NO_X unit shall be subject to the requirements under (a) above and 326 IAC 24-1-4(c)(1) starting on the deadline for meeting the unit's monitor certifications requirements under 326 IAC 24-1-11(c)(1), 11(c)(2), or 11(c)(5) and for each control period thereafter.

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

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

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

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

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

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

(a) As of the allowance transfer deadline, the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR SO_2 allowances available for compliance deductions under for the control period under 326 IAC 24-2-8(j) and 326 IAC 24-2-8(k) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with 326 IAC 24-2-10.

(b) A CAIR SO_2 unit shall be subject to the requirements under (a) above and 326 IAC 24-2-4(c)(1) starting on the deadline for meeting the unit's monitor certifications requirements under 326 IAC 24-2-10(c)(1), 10(c)(2), or 10(c)(5) and for each control period thereafter.

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

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

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

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

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

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

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

(b) A CAIR NO_X unit shall be subject to the requirements under (a) above and 326 IAC 24-3-4(c)(1) starting on the deadline for meeting the unit's monitor certifications requirements under 326 IAC 24-3-11(C)(1), 11(c)(2),11(c)(3), or 11(c)(7) and for each control period thereafter.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Unless otherwise provided, the owners and operators of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall keep on site at the source or at a central location within Indiana for those owners or operators with unattended sources, each of the following documents for a period of five (5) years from the date the document was created:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Source Name: Whiting Clean Energy, Inc
Source Address: 2155 Standard Avenue, Whiting, Indiana 46394
Part 70 Permit No.: T089-29885-00449

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

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify)

☐ Report (specify)

☐ Notification (specify)

☐ Affidavit (specify)

☐ Other (specify)

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

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

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: Whiting Clean Energy, Inc
Source Address: 2155 Standard Avenue, Whiting, Indiana 46394
Part 70 Permit No.: T089-29885-00449

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

☐ This is an emergency as defined in 326 IAC 2-7-1(12) • The Permittee must notify the Office of Air Quality (OAQ), within four (**4**) business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and • The Permittee must submit notice in writing or by facsimile within two (**2**) working days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.

If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:
Control Equipment:
Permit Condition or Operation Limitation in Permit:
Description of the Emergency:
Describe the cause of the Emergency:

If any of the following are not applicable, mark N/A **Page 2 of 2**

Date/Time Emergency started:
Date/Time Emergency was corrected:
Was the facility being properly operated at the time of the emergency? Y N
Type of Pollutants Emitted: TSP, PM-10, SO_2, VOC, NO_X, CO, Pb, other:
Estimated amount of pollutant(s) emitted during emergency:
Describe the steps taken to mitigate the problem:
Describe the corrective actions/response steps taken:
Describe the measures taken to minimize emissions:
If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:

Form Completed by:______________________________

Title / Position: _________________________________

Date:____

Phone: ____

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

Part 70 Quarterly Report

Source Name: Whiting Clean Energy, Inc
Source Address: 2155 Standard Avenue, Whiting, Indiana 46394
Part 70 Permit No.: T089-29885-00449
Facilities: Duct Burner Sets 1 and 2 (DB1 and DB2)
Parameter: Combined natural gas usage
Limit: Less than 8,052 MMSCF per twelve consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Whiting Clean Energy, Inc
Source Address:	2155 Standard Avenue, Whiting, Indiana 46394
Part 70 Permit No.:	T089-29885-00449
Facilities:	Combustion Turbines (CT1 and CT2) and Duct Burner Sets (DB1 and DB2)
Parameter:	Total NO_x emissions, including emissions from startup and shutdown operations
Limit:	Less than 262 tons of NO_x per twelve consecutive month period with compliance determined at the end of each month

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Whiting Clean Energy, Inc
Source Address:	2155 Standard Avenue, Whiting, Indiana 46394
Part 70 Permit No.:	T089-29885-00449
Facilities:	Combustion Turbines (CT1 and CT2) and Duct Burner Sets (DB1 and DB2)
Parameter:	Total CO emissions, including emissions from startup and shutdown operations
Limit:	Less than 571 tons of CO per twelve consecutive month period with compliance determined at the end of each month

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: Whiting Clean Energy, Inc
Source Address: 2155 Standard Avenue, Whiting, Indiana 46394
Part 70 Permit No.: T089-29885-00449
Facilities: Combustion Turbine 1 (CT1)
Parameter: Hours of startup and shutdown
Limit: Less than 473 hours for startups and less than 260 hours for shutdowns per twelve consecutive month period with compliance determined at the end of each month

QUARTER : YEAR:

Month	Hours, this Month		Hours, previous 11 Months		Hours, 12 consecutive month period	
	Startup	Shutdown	Startup	Shutdown	Startup	Shutdown

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Whiting Clean Energy, Inc
Source Address:	2155 Standard Avenue, Whiting, Indiana 46394
Part 70 Permit No.:	T089-29885-00449
Facilities:	Combustion Turbine 2 (CT2)
Parameter:	Hours of startup and shutdown
Limit:	Less than 473 hours for startups and less than 260 hours for shutdowns per twelve consecutive month period with compliance determined at the end of each month

QUARTER :　　　　　　　　YEAR:

Month	Hours, this Month		Hours, previous 11 Months		Hours, 12 consecutive month period	
	Startup	Shutdown	Startup	Shutdown	Startup	Shutdown

☐ No deviation occurred in this quarter.

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

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

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

Source Name: Whiting Clean Energy, Inc
Source Address: 2155 Standard Avenue, Whiting, Indiana 46394
Part 70 Permit No.: T089-29885-00449

Months: __________ to __________ Year: ____________

Page 1 of 2

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

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

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

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

Form Completed by:______________________________

Title / Position: _________________________________

Date:____

Phone: ____

Attachment A: Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 [40 CFR 60, Subpart Da]

Source Background and Description

Source Name:	Whiting Clean Energy, Inc.
Source Location:	2155 Standard Avenue, Whiting, Indiana 46394
County:	Lake
SIC Code:	4911
Part 70 Operating Permit Renewal No.:	T089-29885-00449
Permit Reviewer:	Josiah Balogun

Electric Utility Steam Generating Units NSPS [40 CFR 60, Subpart Da]

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

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

§ 60.40Da Applicability and designation of affected facility.

(a) Except as specified in paragraph (e) of this section, the affected facility to which this subpart applies is each electric utility steam generating unit:

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

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

(b) An IGCC electric utility steam generating unit (both the stationary combustion turbine and any associated duct burners) is subject to this part and is not subject to subpart GG or KKKK of this part if both of the conditions specified in paragraphs (b)(1) and (2) of this section are met.

(1) The IGCC electric utility steam generating unit is capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) The IGCC electric utility steam generating unit commenced construction, modification, or reconstruction after February 28, 2005.

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

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

(e) Applicability of the requirement of this subpart to an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit is as specified in paragraphs (e)(1) and (2) of this section.

(1) Heat recovery steam generators used with duct burners and associated with an electric utility combined cycle gas turbine that are capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel are subject to this subpart except in cases when the heat recovery steam generator meets the applicability requirements and is subject to subpart KKKK of this part.

(2) For heat recovery steam generators use with duct burners subject to this subpart, only emissions resulting from the combustion of fuels in the steam generating unit (i.e. duct burners) are subject to the standards under this subpart. (The emissions resulting from the combustion of fuels in the stationary combustion turbine engine are subject to subpart GG or KKK, as applicable, of this part).

[72 FR 32722, June 13, 2007, as amended at 74 FR 5078, Jan. 28, 2009]

§ 60.41Da Definitions.

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

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

Available purchase power means the lesser of the following:

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

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

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

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

Biomass means plant materials and animal waste.

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

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

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other fuels in any amount.

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

Cogeneration, also known as “combined heat and power,” means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Combined cycle gas turbine means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

Dry flue gas desulfurization technology or *dry FGD* means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides (SO_2) from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry FGD technology include, but are not limited to, lime and sodium.

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

Electric utility combined cycle gas turbine means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

Electric utility company means the largest interconnected organization, business, or governmental entity that generates electric power for sale (*e.g.* , a holding company with operating subsidiary companies).

Electric utility steam-generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

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

Emergency condition means that period of time when:

(1) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

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

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

(2) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(3) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under paragraph (1) of this definition apply.

Emission limitation means any emissions limit or operating limit.

Emission rate period means any calendar month included in a 12-month rolling average period.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

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

Gaseous fuel means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.* , steam delivered to an industrial process).

24-hour period means the period of time between 12:01 a.m. and 12:00 midnight.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. No solid fuel is directly burned in the unit during operation.

Interconnected means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

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

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Neighboring company means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Net system capacity means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

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

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, and residual oil.

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

(1) For particulate matter (PM) is:

(i) 3,000 ng/J (7.0 lb/MMBtu) heat input for solid fuel; and

(ii) 73 ng/J (0.17 lb/MMBtu) heat input for liquid fuels.

(2) For sulfur dioxide (SO_2) is determined under §60.50Da(c).

(3) For nitrogen oxides (NO_X) is:

(i) 290 ng/J (0.67 lb/MMBtu) heat input for gaseous fuels;

(ii) 310 ng/J (0.72 lb/MMBtu) heat input for liquid fuels; and

(iii) 990 ng/J (2.30 lb/MMBtu) heat input for solid fuels.

Potential electrical output capacity means 33 percent of the maximum design heat input capacity of the steam generating unit, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr (*e.g.* , a steam generating unit with a 100 MW (340 MMBtu/hr) fossil-fuel heat input capacity would have a 289,080 MWh 12 month potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

Principal company means the electric utility company or companies which own the affected facility.

Resource recovery unit means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

Responsible official means responsible official as defined in 40 CFR 70.2.

Solid-derived fuel means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, synthetic gas, gasified coal, gasified petroleum coke, gasified biomass, and gasified tire derived fuel.

Spare flue gas desulfurization system module means a separate system of SO_2 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 in ASTM D388 (incorporated by reference, see §60.17).

System emergency reserves means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

System load means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (*e.g.* , emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

Wet flue gas desulfurization technology or *wet FGD* means a SO_2 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.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5079, Jan. 28, 2009]

§ 60.42Da Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain PM in excess of:

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

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the initial PM performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart are exempt from the opacity standard specified in this paragraph b.

(c) Except as provided in paragraph (d) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain PM in excess of:

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

(2) 0.1 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5079, Jan. 28, 2009]

§ 60.43Da Standard for sulfur dioxide (SO_2).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain SO_2in excess of:

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain SO_2in excess of:

(1) 340 ng/J (0.80 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

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

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC–I) any gases that contain SO_2in excess of 520 ng/J (1.20 lb/MMBtu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/MMBtu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite;

(2) Is classified as a resource recovery unit; or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/MMBtu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO_2commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of $SO_2$to the atmosphere are greater than 260 ng/J (0.60 lb/MMBtu) heat input

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = 10$$

(2) If emissions of $SO_2$to the atmosphere are equal to or less than 260 ng/J (0.60 lb/MMBtu) heat input:

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = \frac{(10x + 30y)}{100}$$

Where:

E_s= Prorated SO_2emission limit (ng/J heat input);

$\%P_s$= Percentage of potential SO_2emission allowed;

x = Percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels); and

y = Percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels).

(i) Except as provided in paragraphs (j) and (k) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(j) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, shall caused to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area that commenced construction, reconstruction, or modification commenced after February 28, 2005, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input on a 30-day rolling average basis.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of if the affected facility or 230 ng/J (0.54 lb/MMBtu) heat input on a 30-day rolling average basis.

§ 60.44Da Standard for nitrogen oxides (NOX).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b), (d), (e), and (f) of this section, any gases that contain NO_X(expressed as NO_2) in excess of the following emission limits, based on a 30-day rolling average basis, except as provided under §60.48Da(j)(1):

(1) NO_Xemission limits.

Fuel type	Emission limit for heat input	
	ng/J	lb/MMBtu
Gaseous fuels:		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
Liquid fuels:		
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse	(1)	(1)
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace[2]	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit[2]	260	0.60
Subbituminous coal	210	0.50
Bituminous coal	260	0.60
Anthracite coal	260	0.60
All other fuels	260	0.60

[1]Exempt from NO_Xstandards and NO_Xmonitoring requirements.

[2]Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) NO_Xreduction requirement.

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25
Liquid fuels	30
Solid fuels	65

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(c) Except as provided under paragraphs (d), (e), and (f) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$E_n = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

Where:

E_n= Applicable standard for $NO_X$when multiple fuels are combusted simultaneously (ng/J heat input);

w = Percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x = Percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y = Percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z = Percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v = Percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(d)(1) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction after July 9, 1997, but before or on February 28, 2005 shall cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, based on a 30-day rolling average basis, except as provided under §60.48Da(k).

(2) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of affected facility for which reconstruction commenced after July 9, 1997, but before or on February 28, 2005 shall cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 65 ng/J (0.15 lb/MMBtu) heat input, based on a 30-day rolling average basis.

(e) Except for an IGCC electric utility steam generating unit meeting the requirements of paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X(expressed as NO_2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under §60.48Da(k).

(2) For an affected facility for which reconstruction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis.

(f) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output on a 30-day rolling average basis.

(3) In cases when during a 30-day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

§ 60.45Da Standard for mercury (Hg).

(a) For each coal-fired electric utility steam generating unit other than an IGCC electric utility steam generating unit, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases that contain mercury (Hg) emissions in excess of each Hg emissions limit in paragraphs (a)(1) through (5) of this section that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average basis using the procedures in §60.50Da(h).

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 20×10^{-6} pound per megawatt hour (lb/MWh) or 0.020 lb/gigawatt-hour (GWh) on an output basis. The International System of Units (SI) equivalent is 0.0025 ng/J.

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal:

(i) If your unit is located in a county-level geographical area receiving greater than 25 inches per year (in/yr) mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 66×10^{-6} lb/MWh or 0.066 lb/GWh on an output basis. The SI equivalent is 0.0083 ng/J.

(ii) If your unit is located in a county-level geographical area receiving less than or equal to 25 in/yr mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 97×10^{-6} lb/MWh or 0.097 lb/GWh on an output basis. The SI equivalent is 0.0122 ng/J.

(3) For each coal-fired electric utility steam generating unit that burns only lignite, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 175×10^{-6} lb/MWh or 0.175 lb/GWh on an output basis. The SI equivalent is 0.0221 ng/J.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 16×10^{-6} lb/MWh or 0.016 lb/GWh on an output basis. The SI equivalent is 0.0020 ng/J.

(5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks (*i.e.* , bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the unit-specific Hg emissions limit established according to paragraph (a)(5)(i) or (ii) of this section, as applicable to the affected unit.

(i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the Btu, MWh, or MJ) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 in this section. For each affected source, you must comply with the weighted Hg emissions limit calculated using Equation 1 in this section based on the total Hg emissions from the unit and the total Btu, MWh, or MJ contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^{n} EL_i (HH_i)}{\sum_{i=1}^{n} HH_i} \qquad \text{(Eq. 1)}$$

Where:

EL_b= Total allowable Hg in lb/MWh that can be emitted to the atmosphere from any affected source being averaged according to this paragraph.

EL_i= Hg emissions limit for the subcategory i (coal rank) that applies to affected source, lb/MWh;

HH_i= For each affected source, the Btu, MWh, or MJ contributed by the corresponding subcategory i (coal rank) burned during the compliance period; and

n = Number of subcategories (coal ranks) being averaged for an affected source.

(ii) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse together with one or more non-regulated, supplementary fuels, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emission limit based on the Btu, MWh, or MJ contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 in this section. For each affected source. You must comply with the weighted Hg emissions limit calculated using Equation 1 in this section based on the total Hg emissions from the unit contributed by both regulated and nonregulated fuels burned during the compliance period and the total Btu, MWh, or MJ contributed by both regulated and nonregulated fuels burned during the compliance period.

(b) For each IGCC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases that contain Hg emissions in excess of 20×10^{-6} lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average basis using the procedures in §60.50Da(h).

§ 60.46Da [Reserved]

§ 60.47Da Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC–I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2emission reduction requirements under §60.43Da(c) but must, as a minimum, reduce SO_2emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2emission reduction requirements under §60.43Da(a) but must, as a minimum, reduce SO_2emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NO_Xemission limitation and percent reduction under §60.44Da(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/MMBtu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SCR I)	SO2	6,000–10,000
Fluidized bed combustion (atmospheric)	SO2	400–3,000
Fluidized bed combustion (pressurized)	SO2	400–1,200
Coal liquification	NOX	750–10,000
Total allowable for all technologies		15,000

§ 60.48Da Compliance provisions.

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

(b) Compliance with the NO_Xemission limitation under §60.44Da(a)(1) constitutes compliance with the percent reduction requirements under §60.44Da(a)(2).

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

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if SO_2emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any SO_2emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 MMBtu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph under §60.43Da(a), (b), (d), (e), and (h) for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

(e) After the initial performance test required under §60.8, compliance with the SO_2emission limitations and percentage reduction requirements under §60.43Da and the NO_Xemission limitations under §60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both $SO_2$and $NO_X$and a new percent reduction for $SO_2$are calculated to show compliance with the standards.

(f) For the initial performance test required under §60.8, compliance with the SO_2emission limitations and percent reduction requirements under §60.43Da and the NO_Xemission limitation under §60.44Da is based on the average emission rates for SO_2, NO_X, and percent reduction for $SO_2$for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

(1) Compliance with applicable 30-day rolling average $SO_2$and NO_Xemission limitations is determined by calculating the arithmetic average of all hourly emission rates for $SO_2$and $NO_X$for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_Xonly), or emergency conditions (SO_2only).

(2) Compliance with applicable SO_2percentage reduction requirements is determined based on the average inlet and outlet SO_2emission rates for the 30 successive boiler operating days.

(3) Compliance with applicable daily average PM emission limitations is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. Averages are only calculated for boiler operating days that have valid data for at least 18 hours of unit operation during which the standard applies. Instead, all of the valid hourly emission rates of the operating day(s) not meeting the minimum 18 hours valid data daily average requirement are averaged with all of the valid hourly emission rates of the next boiler operating day with 18 hours or more of valid PM CEMS data to determine compliance.

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

(i) *Compliance provisions for sources subject to §60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), or (f)* . The owner or operator of an affected facility subject to §60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), or (f) shall calculate NO_Xemissions as 1.194×10^{-7} lb/scf-ppm times the average hourly NO_Xoutput concentration in ppm (measured according to the provisions of §60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)). Alternatively, for oil-fired and gas-fired units, NO_Xemissions may be calculated by multiplying the hourly NO_Xemission rate in lb/MMBtu (measured by the CEMS required under §§60.49Da(c) and (d)), by the hourly heat input rate (measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)).

(j) *Compliance provisions for duct burners subject to §60.44Da(a)(1)* . To determine compliance with the emissions limits for NO_Xrequired by §60.44Da(a) for duct burners used in combined cycle systems, either of the procedures described in paragraph (j)(1) or (2) of this section may be used:

(1) The owner or operator of an affected duct burner shall conduct the performance test required under §60.8 using the appropriate methods in appendix A of this part. Compliance with the emissions limits under §60.44Da(a)(1) is determined on the average of three (nominal 1-hour) runs for the initial and subsequent performance tests. During the performance test, one sampling site shall be located in the exhaust of the turbine prior to the duct burner. A second sampling site shall be located at the outlet from the heat recovery steam generating unit. Measurements shall be taken at both sampling sites during the performance test; or

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the CEMS specified under §60.49Da for measuring $NO_X$and oxygen (O_2) (or carbon dioxide (CO_2)) and meet the requirements of §60.49Da. Alternatively, data from a NO_Xemission rate (*i.e.* , NO_X-diluent) CEMS certified according to the provisions of §75.20(c) of this chapter and appendix A to part 75 of this chapter, and meeting the quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used, with the following caveats. Data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit. The NO_Xemission rate at the outlet from the steam generating unit shall constitute the NO_Xemission rate from the duct burner of the combined cycle system.

(k) *Compliance provisions for duct burners subject to §60.44Da(d)(1) or (e)(1)* . To determine compliance with the emission limitation for NO_Xrequired by §60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NO_Xemission limitation in §60.44Da(d)(1) or (e)(1) as follows:

(i) The emission rate (E) of NO_Xshall be computed using Equation 2 in this section:

$$E = \frac{(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})}{(O_{sg} \times h)} \qquad (Eq. 2)$$

Where:

E = Emission rate of $NO_X$from the duct burner, ng/J (lb/MWh) gross output;

C_{sg}= Average hourly concentration of NO_Xexiting the steam generating unit, ng/dscm (lb/dscf);

C_{te}= Average hourly concentration of NO_Xin the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);

Q_{sg}= Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr);

Q_{te}= Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr);

O_{sg}= Average hourly gross energy output from steam generating unit, J (MWh); and

h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(ii) Method 7E of appendix A of this part shall be used to determine the NO_Xconcentrations ($C_{sg}$and C_{te}). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates ($Q_{sg}$and Q_{te}) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable NO_X emission limitation in §60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable NO_X emission limitation in §60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of NO_X shall be computed using Equation 3 in this section:

$$E = \frac{(C_{sg} \times Q_{sg})}{O_{cc}} \qquad (Eq. 3)$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross output;

C_{sg}= Average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf);

Q_{sg}= Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr); and

O_{cc}= Average hourly gross energy output from entire combined cycle unit, J (MWh).

(ii) The CEMS specified under §60.49Da for measuring NO_X and O_2 (or CO_2) shall be used to determine the average hourly NO_X concentrations (C_{sg}). The continuous flow monitoring system specified in §60.49Da(l) or §60.49Da(m) shall be used to determine the volumetric flow rate (Q_{sg}) of the exhaust gas. If the option to use the flow monitoring system in §60.49Da(m) is selected, the flow rate data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit.

(iii) The continuous monitoring system specified under §60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit (O_{cc}), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in §60.49Da(l), determine the mass rate (lb/hr) of NO_X emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of NO_X shall be computed using Equation 4 in this section:

$$E = \frac{(ER_{sg} \times H_{cc})}{O_{cc}} \qquad (Eq. 4)$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross output;

ER_{sg}= Average hourly emission rate of NO_X exiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu);

H_{cc}= Average hourly heat input rate of entire combined cycle unit, J/hr (MMBtu/hr); and

O_{cc}= Average hourly gross energy output from entire combined cycle unit, J (MWh).

(3) When an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

(i) Determine compliance with the applicable NO_Xemissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common steam turbine; or

(ii) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(l) *Compliance provisions for sources subject to §60.45Da.* The owner or operator of an affected facility subject to §60.45Da (new sources constructed or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of §60.49Da(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of §60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in §60.49Da(k). Compliance with the applicable standard under §60.45Da is determined on a 12-month rolling average basis.

(m) *Compliance provisions for sources subject to §60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), or (j)(3)(i).* The owner or operator of an affected facility subject to §60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), or (j)(3)(i) shall calculate SO_2emissions as 1.660×10^{-7}lb/scf-ppm times the average hourly SO_2output concentration in ppm (measured according to the provisions of §60.49Da(b)), times the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)). Alternatively, for oil-fired and gas-fired units, SO_2emissions may be calculated by multiplying the hourly SO_2emission rate (in lb/MMBtu), measured by the CEMS required under §60.49Da, by the hourly heat input rate (measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)).

(n) *Compliance provisions for sources subject to §60.42Da(c)(1)* . The owner or operator of an affected facility subject to §60.42Da(c)(1) shall calculate PM emissions by multiplying the average hourly PM output concentration (measured according to the provisions of §60.49Da(t)), by the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), and divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) *Compliance provisions for sources subject to §60.42Da(c)(2) or (d)* . Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in §60.42Da(c)(2) or (d) by the applicable date specified in §60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months following the date the previous performance test was required to be conducted. You must conduct each performance test according to the requirements in §60.8 using the test methods and procedures in §60.50Da. The owner or operator of an affected facility that has not operated for 60 consecutive calendar days prior to the date that the subsequent performance test would have been required had the unit been operating is not required to perform the subsequent performance test until 30 calendar days after the next boiler operating day. Requests for additional 30 day extensions shall be granted by the relevant air division or office director of the appropriate Regional Office of the U.S. EPA.

(2) You must monitor the performance of each electrostatic precipitator or fabric filter (baghouse) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) using a continuous opacity monitoring system (COMS) according to the requirements in paragraphs (o)(2)(i) through (vi) unless you elect to comply with one of the alternatives provided in paragraphs (o)(3) and (o)(4) of this section, as applicable to your control device.

(i) Each COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B.

(ii) You must comply with the quality assurance requirements in paragraphs (o)(2)(ii)(A) through (E) of this section.

(A) You must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in 40 CFR part 60, appendix B.

(B) You must adjust the zero and span whenever the 24-hour zero drift or 24-hour span drift exceeds 4 percent opacity. The COMS must allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified. The optical surfaces exposed to the effluent gases must be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments. For systems using automatic zero adjustments, the optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(C) You must apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. All procedures applied must provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(D) Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS must be in continuous operation and must complete a minimum of one cycle of sampling and analyzing for each successive 10 second period and one cycle of data recording for each successive 6-minute period.

(E) You must reduce all data from the COMS to 6-minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments must not be included in the data averages. An arithmetic or integrated average of all data may be used.

(iii) During each performance test conducted according to paragraph (o)(1) of this section, you must establish an opacity baseline level. The value of the opacity baseline level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurements recorded during each of the test run intervals conducted for the performance test, and then adding 2.5 percent opacity to your calculated average opacity value for all of the test runs. If your opacity baseline level is less than 5.0 percent, then the opacity baseline level is set at 5.0 percent.

(iv) You must evaluate the preceding 24-hour average opacity level measured by the COMS each boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the measured 24-hour average opacity emission level is greater than the baseline opacity level determined in paragraph (o)(2)(iii) of this section, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high opacity incident and take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the measured 24-hour average opacity to a level below the baseline opacity level. In cases when a wet scrubber is used in combination with another PM control device that serves as the primary PM control device, the wet scrubber must be maintained and operated.

(v) You must record the opacity measurements, calculations performed, and any corrective actions taken. The record of corrective action taken must include the date and time during which the measured 24-hour average opacity was greater than baseline opacity level, and the date, time, and description of the corrective action.

(vi) If the measured 24-hour average opacity for your affected facility remains at a level greater than the opacity baseline level after 7 boiler operating days, then you must conduct a new PM performance test according to paragraph (o)(1) of this section and establish a new opacity baseline value according to paragraph (o)(2) of this section. This new performance test must be conducted within 60 days of the date that the measured 24-hour average opacity was first determined to exceed the baseline opacity level unless a waiver is granted by the permitting authority.

(3) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of an electrostatic precipitator (ESP) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) using an ESP predictive model developed in accordance with the requirements in paragraphs (o)(3)(i) through (v) of this section.

(i) You must calibrate the ESP predictive model with each PM control device used to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) operating under normal conditions. In cases when a wet scrubber is used in combination with an ESP to comply with the PM emissions limit, the wet scrubber must be maintained and operated.

(ii) You must develop a site-specific monitoring plan that includes a description of the ESP predictive model used, the model input parameters, and the procedures and criteria for establishing monitoring parameter baseline levels indicative of compliance with the PM emissions limit. You must submit the site-specific monitoring plan for approval by the permitting authority. For reference purposes in preparing the monitoring plan, see the OAQPS “Compliance Assurance Monitoring (CAM) Protocol for an Electrostatic Precipitator (ESP) Controlling Particulate Matter (PM) Emissions from a Coal-Fired Boiler.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality Planning and Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Continuous Emission Monitoring.

(iii) You must run the ESP predictive model using the applicable input data each boiler operating day and evaluate the model output for the preceding boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the values for one or more of the model parameters exceed the applicable baseline levels determined according to your approved site-specific monitoring plan, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of a model parameter deviation and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to return the model output to within the applicable baseline levels.

(iv) You must record the ESP predictive model inputs and outputs and any corrective actions taken. The record of corrective action taken must include the date and time during which the model output values exceeded the applicable baseline levels, and the date, time, and description of the corrective action.

(v) If after 7 consecutive days a model parameter continues to exceed the applicable baseline level, then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 calendar days of the date that the model parameter was first determined to exceed its baseline level unless a waiver is granted by the permitting authority.

(4) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of a fabric filter (baghouse) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) by using a bag leak detection system according to the requirements in paragraphs (o)(4)(i) through (v) of this section.

(i) Each bag leak detection system must meet the specifications and requirements in paragraphs (o)(4)(i)(A) through (H) of this section.

(A) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic foot) or less.

(B) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator must continuously record the output from the bag leak detection system using electronic or other means (*e.g.* , using a strip chart recorder or a data logger.)

(C) The bag leak detection system must be equipped with an alarm system that will react when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (o)(4)(i)(D) of this section, and the alarm must be located such that it can be noticed by the appropriate plant personnel.

(D) In the initial adjustment of the bag leak detection system, you must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(E) Following initial adjustment, you must not adjust the averaging period, alarm set point, or alarm delay time without approval from the permitting authority except as provided in paragraph (d)(1)(vi) of this section.

(F) Once per quarter, you may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (o)(4)(ii) of this section.

(G) You must install the bag leak detection sensor downstream of the fabric filter and upstream of any wet scrubber.

(H) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(ii) You must develop and submit to the permitting authority for approval a site-specific monitoring plan for each bag leak detection system. You must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (o)(4)(ii)(A) through (F) of this section.

(A) Installation of the bag leak detection system;

(B) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(C) Operation of the bag leak detection system, including quality assurance procedures;

(D) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(E) How the bag leak detection system output will be recorded and stored; and

(F) Corrective action procedures as specified in paragraph (o)(4)(iii) of this section. In approving the site-specific monitoring plan, the permitting authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

(iii) For each bag leak detection system, you must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (o)(4)(ii)(F) of this section, you must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

(A) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(B) Sealing off defective bags or filter media;

(C) Replacing defective bags or filter media or otherwise repairing the control device;

(D) Sealing off a defective fabric filter compartment;

(E) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(F) Shutting down the process producing the particulate emissions.

(iv) You must maintain records of the information specified in paragraphs (o)(4)(iv)(A) through (C) of this section for each bag leak detection system.

(A) Records of the bag leak detection system output;

(B) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(C) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 3 hours of the alarm.

(v) If after any period composed of 30 boiler operating days during which the alarm rate exceeds 5 percent of the process operating time (excluding control device or process startup, shutdown, and malfunction), then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 calendar days of the date that the alarm rate was first determined to exceed 5 percent limit unless a waiver is granted by the permitting authority.

(5) An owner or operator of a modified affected facility electing to meet the emission limitations in §60.42Da(d) shall determine the percent reduction in PM by using the emission rate for PM determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, evaluate, maintain, and operate a CEMS measuring PM emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a CEMS measuring PM. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each CEMS shall be installed, evaluated, operated, and maintained according to the requirements in §60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19 of appendix A of this part, section 4.1.

(5) At a minimum, valid CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-day rolling average basis. Beginning on January 1, 2012, valid CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average basis.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/hr, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(7) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30-day rolling average.

(q) *Compliance provisions for sources subject to §60.42Da(b)* . An owner or operator of an affected facility subject to the opacity standard in §60.42Da(b) shall monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the requirements in §60.49Da(a), as applicable to the affected facility.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5079, Jan. 28, 2009]

§ 60.49Da Emission monitoring.

(a) An owner or operator of an affected facility subject to the opacity standard in §60.42Da(b) shall monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the applicable requirements in paragraphs (a)(1) through (3) of this section.

(1) Except as provided for in paragraph (a)(2) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a COMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO_2control system),

alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(2) As an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), or (iii) of this section may elect to monitor opacity as specified in paragraph (a)(3) of this section.

(i) The affected facility uses a fabric filter (baghouse) to meet the standards in §60.42Da and a bag leak detection system is installed and operated according to the requirements in paragraphs §60.48Da(o)(4)(i) through (v);

(ii) The affected facility burns only gaseous or liquid fuels (excluding residual oil) with potential SO_2emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO_2or PM; or

(iii) The affected facility meets all of the conditions specified in paragraphs (a)(2)(iii)(A) through (C) of this section.

(A) No post-combustion technology (except a wet scrubber) is used for reducing PM, SO_2, or carbon monoxide (CO) emissions;

(B) Only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur are burned; and

(C) Emissions of CO discharged to the atmosphere are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis as demonstrated by the use of a CEMS measuring CO emissions according to the procedures specified in paragraph (u) of this section.

(3) The owner or operators of an affected facility that meets the conditions in paragraph (a)(2) of this section may, as an alternative to COMS, elect to monitor visible emissions using the applicable procedures specified in paragraphs (a)(3)(i) through (iv) of this section.

(i) The owner or operator shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in §60.11. If during the initial 60 minutes of the observation all the 6-minute averages are less than 10 percent and all the individual 15-second observations are less than or equal to 20 percent, then the observation period may be reduced from 3 hours to 60 minutes.

(ii) Except as provided in paragraph (a)(3)(iii) or (iv) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (a)(3)(i) of this section according to the applicable schedule in paragraphs (a)(3)(ii)(A) through (a)(3)(ii)(D) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

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

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

(D) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 30 calendar days from the date that the most recent performance test was conducted.

(iii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (a)(3)(iii)(A) and (B) of this section.

(A) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.* , 90 seconds per 30 minute period) the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.* , 90 seconds) or conduct a new Method 9 of appendix A–4 of this part performance test using the procedures in paragraph (a)(3)(i) of this section within 30 calendar days according to the requirements in §60.50Da(b)(3).

(B) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(iv) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(3)(iii) of this section. For reference purposes in preparing the monitoring plan, see OAQPS “Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2control device.

(2) For a facility that qualifies under the numerical limit provisions of §60.43Da(d), (i), (j), or (k) SO_2emissions are only monitored as discharged to the atmosphere.

(3) An “as fired” fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of appendix A of this part may be used to determine potential SO_2emissions in place of a continuous SO_2emission monitor at the inlet to the SO_2control device as required under paragraph (b)(1) of this section.

(4) If the owner or operator has installed and certified a SO_2CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used to meet the requirements of this section, provided that:

(i) A CO_2or O_2continuous monitoring system is installed, calibrated, maintained and operated at the same location, according to paragraph (d) of this section; and

(ii) For sources subject to an SO_2emission limit in lb/MMBtu under §60.43Da:

(A) When relative accuracy testing is conducted, SO_2concentration data and CO_2(or O_2) data are collected simultaneously; and

(B) In addition to meeting the applicable $SO_2$and CO_2(or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(iii) The reporting requirements of §60.51Da are met. The $SO_2$and, if required, CO_2(or O_2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2data have been bias adjusted according to the procedures of part 75 of this chapter.

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_Xemissions discharged to the atmosphere; or

(2) If the owner or operator has installed a NO_Xemission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to

meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.51Da. Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility not complying with an output based limit shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2or carbon dioxide (CO_2) content of the flue gases at each location where SO_2or NO_Xemissions are monitored. For affected facilities subject to a lb/MMBtu SO_2emission limit under §60.43Da, if the owner or operator has installed and certified a CO_2or O_2monitoring system according to §75.20(c) of this chapter and appendix A to part 75 of this chapter and the monitoring system continues to meet the applicable quality-assurance provisions of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used together with the part 75 SO_2concentration monitoring system described in paragraph (b) of this section, to determine the SO_2emission rate in lb/MMBtu. SO_2data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

(f)(1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph §60.13(h) are expressed in ng/J (lb/MMBtu) heat input and used to calculate the average emission rates under §60.48Da. The 1-hour averages are calculated using the data points required under §60.13(h)(2).

(h) When it becomes necessary to supplement CEMS data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 of appendix A of this part shall be used to determine the SO_2concentration at the same location as the SO_2monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 of appendix A of this part shall be used to determine the NO_Xconcentration at the same location as the NO_Xmonitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2or CO_2concentration at the same location as the O_2or CO_2monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 of appendix A of this part shall be used to compute each 1-hour average concentration in ng/J (lb/MMBtu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under §60.13(c) and calibration checks under §60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7 of appendix A of this part shall be used to determine O_2, SO_2, and NO_Xconcentrations, respectively.

(2) SO_2or NO_X(NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a COMS is between 60 and 80 percent. Span values for a CEMS measuring NO_Xshall be determined using one of the following procedures:

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

Fossil fuel	**Span values for NO_X (ppm)**
Gas	500.
Liquid	500.
Solid	1,000.
Combination	500 (x + y) + 1,000z.

Where:

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

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

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

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

(4) All span values computed under paragraph (i)(3)(i) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (i)(3)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel and determining span values under paragraph (i)(3)(i) of this section, the span value of the SO_2CEMS at the inlet to the SO_2control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the SO_2control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired. For affected facilities determining span values under paragraph (i)(3)(ii) of this section, SO_2span values shall be determined according to section 2.1.1 in appendix A to part 75 of this chapter.

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

(1) For Method 6 of appendix A of this part, Method 6A or 6B (whenever Methods 6 and 3 or 3B of appendix A of this part data are used) or 6C of appendix A of this part may be used. Each Method 6B of appendix A of this part sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B of appendix A of this part is used under paragraph (i) of this section, the conditions under §60.48Da(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

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

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

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

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under §§60.42Da(c), 60.43Da(i), 60.43Da(j), 60.44Da(d)(1), and 60.44Da(e).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in MWh on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under §60.42Da, §60.43Da, §60.44Da, or §60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the CD assessment, RATA and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of §75.20(c) of this chapter and appendix A to part 75 of this chapter, and continuing to meet the applicable quality control and quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used. Flow rate data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of part 75 of this chapter.

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

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in §60.45Da shall install and operate a CEMS to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to §75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of each CEMS according to the requirements of §60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in §60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in §60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (i.e., valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in §72.2 of this chapter) to monitor Hg concentration, according to the procedures described in §75.15 of this chapter and appendix K to part 75 of this chapter.

(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of §75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in §75.11(b) or §75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (*e.g.* , on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of §60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of §60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing recordkeeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under §60.42Da(c)(1) shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected facility demonstrating compliance with the input-based emission limitation in §60.42Da(a)(1) or §60.42Da(c)(2) may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) The owner or operator of an affected facility using a CEMS measuring CO emissions to meet requirements of this subpart shall meet the requirements specified in paragraphs (u)(1) through (4) of this section.

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (u)(1)(i) through (iv) of this section.

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

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

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

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

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

(3) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 1.4 lb/MWh, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 1.4 lb/MWh or less.

(4) You must record the CO measurements and calculations performed according to paragraph (u)(3) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 1.4 lb/MWh, and the date, time, and description of the corrective action.

(v) The owner or operator of an affected facility using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (v)(1) through (v)(4) of this section.

(1) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of §60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each PM correlation testing run of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2(or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the CEMS and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

(ii) After July 1, 2010 or after Method 202 of appendix M of part 51 has been revised to minimize artifact measurement and notice of that change has been published in theFederal Register,whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

(iii) For O_2(or CO_2), Method 3A or 3B of appendix A–2 of this part, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(4) After July 1, 2011, within 90 days after the date of completing each performance evaluation required by paragraph (v) of this section, the owner or operator of the affected facility must either submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at

http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243–01; RTP, NC 27711.

(w) The owner or operator using a SO_2, NO_X, CO_2, and O_2CEMS to meet the requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (w)(1) through (w)(5) of this section.

(1) Except as provided for under paragraphs (w)(2), (w)(3), and (w)(4) of this section, each SO_2, NO_X, CO_2, and O_2CEMS required under paragraphs (b) through (d) of this section shall be installed, certified, and operated in accordance with the applicable procedures in Performance Specification 2 or 3 in appendix B to this part or according to the procedures in appendices A and B to part 75 of this chapter. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in appendix F to this part, and a data assessment report (DAR), prepared according to section 7 of Procedure 1 in appendix F to this part, shall be submitted with each compliance report required under §60.51Da.

(2) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to implement the following alternative data accuracy assessment procedures. For all required $CO_2$and O_2CEMS and for $SO_2$and NO_XCEMS with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F of this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to $SO_2$and NO_Xspan values less than 100 ppm;

(3) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For all required $CO_2$and O_2CEMS and for $SO_2$and NO_XCEMS with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for $SO_2$and NO_Xspan values less than or equal to 30 ppm;

(4) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For SO_2, CO_2, and O_2CEMS and for NO_XCEMS, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2(regardless of the SO_2emission level during the RATA), and for $NO_X$when the average NO_Xemission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu;

(5) If the owner or operator elects to implement the alternative data assessment procedures described in paragraphs (w)(2) through (w)(4) of this section, each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by paragraphs (w)(2) through (w)(4) of this section.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5081, Jan. 28, 2009]

§ 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for $SO_2$and NO_X. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the PM standards in §60.42Da as follows:

(1) The dry basis F factor (O_2) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(2) For the particular matter concentration, Method 5 of appendix A of this part shall be used at affected facilities without wet FGD systems and Method 5B of appendix A of this part shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160±14 °C (320±25 °F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the O_2concentration. The O_2sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2traverse points. If the grab sampling procedure is used, the O_2concentration for the run shall be the arithmetic mean of the sample O_2concentrations at all traverse points.

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

(c) The owner or operator shall determine compliance with the SO_2standards in §60.43Da as follows:

(1) The percent of potential SO_2emissions (%Ps) to the atmosphere shall be computed using the following equation:

$$\%P_s = \frac{(100 - \%R_f)(100 - \%R_g)}{100}$$

Where:

%Ps = Percent of potential SO_2emissions, percent;

%Rf = Percent reduction from fuel pretreatment, percent; and

%Rg = Percent reduction by SO_2control system, percent.

(2) The procedures in Method 19 of appendix A of this part may be used to determine percent reduction ($\%R_f$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and fly ash interactions. This determination is optional.

(3) The procedures in Method 19 of appendix A of this part shall be used to determine the percent SO_2reduction ($\%R_g$) of any SO_2control system. Alternatively, a combination of an “as fired” fuel monitor and emission rates measured after the control system, following the procedures in Method 19 of appendix A of this part, may be used if the percent reduction is calculated using the average emission rate from the SO_2control device and the average SO_2input rate from the “as fired” fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate.

(5) The CEMS in §60.49Da(b) and (d) shall be used to determine the concentrations of $SO_2$and CO_2or O_2.

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

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

(2) The continuous monitoring system in §60.49Da(c) and (d) shall be used to determine the concentrations of $NO_X$and CO_2or O_2.

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

(1) For Method 5 or 5B of appendix A–3 of this part, Method 17 of appendix A–6 of this part may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A–3 of this part may be used in Method 17 of appendix A–6 of this part only if it is used after wet FGD systems. Method 17 of appendix A–6 of this part shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The $F_c$factor (CO_2) procedures in Method 19 of appendix A of this part may be used to compute the emission rate of PM under the stipulations of §60.46(d)(1). The CO_2shall be determined in the same manner as the O_2concentration.

(f) Electric utility combined cycle gas turbines that are not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas are performance tested for PM, SO_2, and NO_Xusing the procedures of Method 19 of appendix A–7 of this part. The $SO_2$and NO_Xemission rates calculations from the gas turbine used in Method 19 of appendix A–7 of this part are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

(g) For the purposes of determining compliance with the emission limits in §60.45Da, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus 75 percent of the equivalent electrical energy (measured relative to ISO conditions) in the unit's process stream.

(1) All conversions from Btu/hr unit input to MW unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (*i.e.* , 250 MMBtu/hr input to an electric utility steam generating unit is equivalent to 73 MW input to the electric utility steam generating unit); 73 MW input to the electric utility steam generating unit is equivalent to 25 MW output from the boiler electric utility steam generating unit; therefore, 250 MMBtu input to the electric utility steam generating unit is equivalent to 25 MW output from the electric utility steam generating unit).

(2) Use the Equation 5 in this section to determine the cogeneration Hg emission rate over a specific compliance period.

$$ER_{cogen} = \frac{M}{\left(V_{grid} + 0.75 \times V_{process}\right)} \qquad \text{(Eq. 5)}$$

Where:

ER_{cogen}= Cogeneration Hg emission rate over a compliance period in lb/MWh;

E = Mass of Hg emitted from the stack over the same compliance period (lb);

V_{grid}= Amount of energy sent to the grid over the same compliance period (MWh); and

$V_{process}$= Amount of energy converted to steam for process use over the same compliance period (MWh).

(h) The owner or operator shall determine compliance with the Hg limit in §60.45Da according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The initial performance test shall be commenced by the applicable date specified in §60.8(a). The required CEMS must be certified prior to commencing the test. The performance test consists of collecting hourly Hg emission data (lb/MWh) with the CEMS for 12 successive months of unit operation (excluding hours of unit startup, shutdown and malfunction). The average Hg emission rate is calculated for each month, and then the weighted, 12-month average Hg emission rate is calculated according to paragraph (h)(2) or (h)(3) of this section, as applicable. If, for any month in the initial performance test, the minimum data capture requirement in §60.49Da(p)(4)(i) is not met, the owner or operator shall report a substitute Hg emission rate for that month, as follows. For the first such month, the substitute monthly Hg emission rate shall be the arithmetic average of all valid hourly Hg emission rates recorded to date. For any subsequent month(s) with insufficient data capture, the substitute monthly Hg emission rate shall be the highest valid hourly Hg emission rate recorded to date. When the 12-month average Hg emission rate for the initial

performance test is calculated, for each month in which there was insufficient data capture, the substitute monthly Hg emission rate shall be weighted according to the number of unit operating hours in that month. Following the initial performance test, the owner or operator shall demonstrate compliance by calculating the weighted average of all monthly Hg emission rates (in lb/MWh) for each 12 successive calendar months, excluding data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (iii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in lb, using either Equation 6 in paragraph (h)(2)(i)(A) of this section or Equation 7 in paragraph (h)(2)(i)(B) of this section, in conjunction with Equation 8 in paragraph (h)(2)(i)(C) of this section.

(A) If the Hg CEMS measures Hg concentration on a wet basis, use Equation 6 below to calculate the Hg mass emissions for each valid hour:

$$E_h = KC_h Q_h t_h \qquad \text{(Eq. 6)}$$

Where:

E_h= Hg mass emissions for the hour, (lb);

K = Units conversion constant, 6.24×10^{-11} lb-scm/µgm-scf;

C_h= Hourly $H_g$concentration, wet basis, (µgm/scm);

Q_h= Hourly stack gas volumetric flow rate, (scfh); and

t_h= Unit operating time, i.e., the fraction of the hour for which the unit operated. For example, th = 0.50 for a half-hour of unit operation and 1.00 for a full hour of operation.

(B) If the Hg CEMS measures Hg concentration on a dry basis, use Equation 7 below to calculate the Hg mass emissions for each valid hour:

$$E_h = KC_h Q_h t_h (1 - B_{ws}) \qquad \text{(Eq. 7)}$$

Where:

E_h= Hg mass emissions for the hour, (lb);

K = Units conversion constant, 6.24×10^{-11}lb-scm/µgm-scf;

C_h= Hourly Hg concentration, dry basis, (µgm/dscm);

Q_h= Hourly stack gas volumetric flow rate, (scfh);

t_h= Unit operating time, *i.e.* , the fraction of the hour for which the unit operated; and

B_{ws}= Stack gas moisture content, expressed as a decimal fraction (*e.g.* , for 8 percent H_2O, B_{ws}= 0.08).

(C) Use Equation 8, below, to calculate M, the total mass of Hg emitted for the month, by summing the hourly masses derived from Equation 6 or 7 (as applicable):

$$M = \sum_{h=1}^{n} E_h \qquad \text{(Eq. 8)}$$

Where:

M = Total Hg mass emissions for the month, (lb);

E_h= Hg mass emissions for hour “h”, from Equation 6 or 7 of this section, (lb); and

n = Number of unit operating hours in the month with valid CE and electrical output data, excluding hours of unit startup, shutdown and malfunction.

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 9, below. For a cogeneration unit, use Equation 5 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \qquad (Eq. 9)$$

Where:

ER = Monthly Hg emission rate, (lb/MWh);

M = Total mass of Hg emissions for the month, from Equation 8, above, (lb); and

P = Total electrical output for the month, for the hours used to calculate M, (MWh).

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 10 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=1}^{12}(ER_i \times n_i)}{\sum_{i=1}^{12} n_i} \qquad (Eq. 10)$$

Where:

E_{avg}= Weighted 12-month rolling average Hg emission rate, (lb/MWh);

ER_i= Monthly Hg emission rate, for month “i”, (lb/MWh); and

n = Number of unit operating hours in month “i” with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction.

(3) If a sorbent trap monitoring system is used in lieu of a Hg CEMS, as described in §75.15 of this chapter and in appendix K to part 75 of this chapter, calculate the monthly Hg emission rates using Equations 7 through 9 of this section, except that for a particular pair of sorbent traps, $C_h$in Equation 7 shall be the flow-proportional average Hg concentration measured over the data collection period.

(i) Daily calibration drift (CD) tests and quarterly accuracy determinations shall be performed for Hg CEMS in accordance with Procedure 1 of appendix F to this part. For the CD assessments, you may use either elemental mercury or mercuric chloride (Hg° $HgCl_2$) standards. The four quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using $HgCl_2$standards, as described in section 8.3 of Performance Specification 12–A in appendix B to this part (note: Hg° standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5083, Jan. 28, 2009]

§ 60.51Da Reporting requirements.

(a) For SO_2, NO_X, PM, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For $SO_2$and $NO_X$the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average $SO_2$and NO_Xemission rates (ng/J, lb/MMBtu, or lb/MWh) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) For owners or operators of affected facilities complying with the percent reduction requirement, percent reduction of the potential combustion concentration of $SO_2$for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_Xonly), emergency conditions (SO_2only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(9) Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of §60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates (n_i) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (E_o*) and the upper confidence limit for the mean inlet emission rate (E_i*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.

(d) If any standards under §60.43Da are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under §60.48Da(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the SO_2emission standard under §60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of §60.50Da and Method 19 of appendix A of this part; and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, SO_2or NO_Xemissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) For Hg, the following information shall be reported to the Administrator:

(1) Company name and address;

(2) Date of report and beginning and ending dates of the reporting period;

(3) The applicable Hg emission limit (lb/MWh); and

(4) For each month in the reporting period:

(i) The number of unit operating hours;

(ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;

(iii) The monthly Hg emission rate (lb/MWh);

(iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and

(v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

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

(1) The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for $SO_2$and/or $NO_X$and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

[72 FR 32722, June 13, 2007, as amended at 74 FR 5083, Jan. 28, 2009]

§ 60.52Da Recordkeeping requirements.

(a) The owner or operator of an affected facility subject to the emissions limitations in §60.45Da shall provide notifications in accordance with §60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of §60.7(f).

(b) The owner or operator of an affected facility subject to the opacity limits in §60.42Da(b) that elects to monitor emissions according to the requirements in §60.49Da(a)(3) shall maintain records according to the requirements specified in paragraphs (b)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (b)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (b)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

[74 FR 5083, Jan. 28, 2009]

Attachment B: Standards of Performance for Stationary Gas Turbines [40 CFR 60, Subpart GG]

Source Background and Description

Source Name:	Whiting Clean Energy, Inc.
Source Location:	2155 Standard Avenue, Whiting, Indiana 46394
County:	Lake
SIC Code:	4911
Part 70 Operating Permit Renewal No.:	T089-29885-00449
Permit Reviewer:	Josiah Balogun

Stationary Gas Turbines NSPS [40 CFR 60, Subpart GG]

Subpart GG—Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

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

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

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000]

§ 60.331 Definitions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, combuster inlet pressure, combuster inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) *Electric utility stationary gas turbine* means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

(r) *Emergency fuel* is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) *Unit operating hour* means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

(t) *Excess emissions* means a specified averaging period over which either:

(1) The NO_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.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 60.332 Standard for nitrogen oxides.

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

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

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

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_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.

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

$$STD = 0.0150\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_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 peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_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.

(4) If the owner or operator elects to apply a NO_X emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under §60.8 as follows:

Fuel-bound nitrogen (percent by weight)	F (NO_Xpercent by volume)
N ≤ .015	0
0.015 < N≤ 0.1	0.04 (N)
0.1 < N ≤ 0.25	0.004+0.0067(N–0.1)
N > 0.25	0.005

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by §60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in theFederal Register.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in §60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO_Xemissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979,Federal Register(44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by §60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

[44 FR 52798, Sept. 10, 1979, as amended at 69 FR 41360, July 8, 2004]

§ 60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_Xemissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_Xemissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of $NO_X$and O_2monitors. As an alternative, a CO_2monitor may be used to adjust the measured NO_Xconcentrations to 15 percent $O_2$by either converting the CO_2hourly averages to equivalent O_2concentrations using Equation F–14a or F–14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O_2, or by using the CO_2readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the $NO_X$and diluent monitors may be performed individually or on a combined basis, *i.e.* , the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO_X) and a percent O_2basis for oxygen; or

(ii) On a ppm at 15 percent O_2basis; or

(iii) On a ppm basis (for NO_X) and a percent CO_2basis (for a CO_2monitor that uses the procedures in Method 20 to correct the NO_Xdata to 15 percent O_2).

(2) As specified in §60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in §60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both $NO_X$and diluent, the data acquisition and handling system must calculate and record the hourly NO_Xemissions in the units of the applicable NO_Xemission standard under §60.332(a), *i.e.* , percent $NO_X$by volume, dry basis, corrected to 15 percent $O_2$and International Organization for Standardization (ISO) standard conditions (if required as given in §60.335(b)(1)). For any hour in which the hourly average O_2concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(iii) If the owner or operator has installed a NO_XCEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_Xemissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable NO_Xemission limit under §60.332, that approved procedure may continue to be used.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO_Xemissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO_XCEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO_Xemissions, may, but is not required to, elect to use a NO_XCEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.

(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control NO_Xemissions may, but is not required to, perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO_Xformation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_Xmode.

(3) For any turbine that uses SCR to reduce NO_Xemissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO_Xemission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in §75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under §60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_Xemission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in §75.19 of this chapter or the NO_Xemission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in §75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

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

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (*i.e.* , if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332). The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.* , flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(*1*) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*2*) of this section.

(*2*) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*3*) of this section.

(*3*) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (*i.e.* , the maximum total sulfur content of natural gas as defined in §60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in §60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NO_X and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_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).

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (*i.e.* , daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) *Ice fog.* Each period during which an exemption provided in §60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated

shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) *Emergency fuel.* Each period during which an exemption provided in §60.332(k) is in effect shall be included in the report required in §60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each 6-month period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41360, July 8, 2004; 71 FR 9457, Feb. 24, 2006]

§ 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in §60.8, using either

(1) EPA Method 20,

(2) ASTM D6522–00 (incorporated by reference, see §60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NO_X and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_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.

(4) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522–00 (incorporated by reference, see §60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 NO_X emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in §60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_X CEMS under §60.334(e), then the initial performance test required under §60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator elects under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597–94 (Reapproved 1999), D6366–99, D4629–02, D5762–02 (all of which are incorporated by reference, *see* §60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under §60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01 (all of which are incorporated by reference, *see* §60.17); or

(ii) For gaseous fuels, ASTM D1072–80, 90 (Reapproved 1994); D3246–81, 92, 96; D4468–85 (Reapproved 2000); or D6667–01 (all of which are incorporated by reference, see §60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

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

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in §60.8 to ISO standard day conditions.

[69 FR 41363, July 8, 2004, as amended at 71 FR 9458, Feb. 24, 2006]

Indiana Department of Environmental Management
Office of Air Quality

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

Source Background and Description

Source Name:	Whiting Clean Energy, Inc.
Source Location:	2155 Standard Avenue, Whiting, Indiana 46394
County:	Lake
SIC Code:	4911
Part 70 Operating Permit Renewal No.:	T089-29885-00449
Permit Reviewer:	Josiah Balogun

The Office of Air Quality (OAQ) has reviewed the operating permit renewal application from Whiting Clean Energy, Inc. relating to the operation of a stationary industrial steam and 545 MWe co-generation ("combined heat and power") plant**.** On November 17, 2010, Whiting Clean Energy, Inc submitted an application to the OAQ requesting to renew its operating permit. Whiting Clean Energy, Inc was issued Part 70 Operating Permit Renewal T089-16167-00449 on August 2006.

Permitted Emission Units and Pollution Control Equipment

The source consists of the following permitted emission units:

(a) Two (2) Combined-cycle Combustion Turbines (CT), each constructed in 2001:

Make/Model:	General Electric Frame 7FA (Model 7241)
Heat Input Capacity (HIC):	1,735 MMBtu per hour (HHV) @ ISO conditions, each
Electric Generating Capacity:	166 MW @ ISO conditions, each
Fuel Source:	Natural Gas
Control Technology:	Dry Low-NO_x Burners
Stack ID:	CT1 exhausts through HRSG1 to stack 1 CT2 exhausts through HRSG2 to stack 2

(b) Two (2) Heat Recovery Steam Generators (HRSG), each with a Duct Burner set (DB), each constructed in 2001:

Steam Generating Capacity:	1300 psig
Duct Burner HIC:	821 MMBtu per hour (HHV), per set
Fuel Source:	Natural Gas
Control Technology:	Selective Catalytic Reduction (SCR) System for NOx control
Steam Production Capacity:	580,000 pounds per hour, each, without DBs 1,188,000 pounds per hour, each, with DBs
Stack ID:	DB1 exhausts to stack 1 DB2 exhausts to stack 2

(c) One (1) Condensing Steam Turbine Generator (CSTG), constructed in 2001:
Electric Generating Capacity: 213 MW @ 1,600,000 pounds per hour steam

(d) One (1) Induced Draft Non-Contact Cooling Tower, constructed in 2001:

System Technology:	5 cycle, 10 cell, induced draft cooling tower
Water Circulation Rate:	160,000 gallons per minute non-contact cooling water
Control Technology:	Drift Eliminator for particulate control
Stack ID:	Stacks C1 through C10

Note that the Condensing Steam Turbine Generator (CSTG) is not a source of emissions. It utilizes the steam produced from the Heat Recovery Steam Generators (HRSGs) to produce electricity. The CSTG has been included for clarity because it is a part of the entire source and operates in conjunction with the HRSGs and cooling tower (which is a source of emissions). As a result, the CSTG is not mentioned further in this document.

Also note that the Heat Recovery Steam Generators (HRSGs) 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 Burner Sets (which are a source of emissions). As a result, the HRSGs are not mentioned further in this document.

Emission Units and Pollution Control Equipment Constructed and/or Operated without a Permit

Since issuance of the last approval, the source has not constructed and is not operating any new emission units that required IDEM approval prior to construction and operation.

Emission Units and Pollution Control Equipment Removed From the Source

Since issuance of the last approval, the source has not removed any emission units or control equipment.

Insignificant Activities

The source also consists of the following insignificant activities:

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

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

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

(c) The following equipment related to maintenance activities not resulting in the emission of HAPs (sources of fugitive emissions): brazing equipment, cutting torches, soldering equipment, welding equipment.

(d) Natural gas-fired combustion sources with heat input equal to or less than ten million (10,000,000) Btu per hour.

(e) Combustion source flame safety purging on startup.

(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) Application of oils, greases, lubricants or other nonvolatile materials applied as temporary protective coatings.

(h) Cleaners and solvents characterized as having a vapor pressure equal to or less than 2 kPa; 15mm Hg; or 0.3 psi measured at 38 ^{o}C (100^{o}F) or; having a vapor pressure equal to or less than 0.7 kPa; 5 mm Hg; or 0.1 psi measured at 20^{o}C (68^{o}F); the use of which for all cleaners and solvents combined does not exceed 145 gallons per 12 months.

(i) Closed loop heating and cooling systems.

(j) Noncontact, forced and induced, draft cooling tower system not regulated under a NESHAP.

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

(l) Heat exchanger cleaning and repair.

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

(n) Purge double block and bleed valves.

(o) Filter or coalescer media changeout.

(p) 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.

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

(r) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including catch tanks, temporary liquid separators, tanks, and fluid handling equipment.

Existing Approvals

Since the issuance of the Part 70 Operating Permit T089-16167-00449, issued on August 16, 2006, the source has constructed or has been operating under the following additional approvals:

(a) Review Request No. 089-26104-00449, issued on February 22, 2008;

(b) Significant Permit Modification No. 089-23668-00449, issued on March 12, 2008;

(c) Acid Rain Renewal No. 089-22465-00449, issued on October 23, 2008; and

(d) Significant Permit Modification No. 089-26393-00449, issued on May 5, 2009.

All terms and conditions of previous permits issued pursuant to permitting programs approved into the State Implementation Plan have been either incorporated as originally stated, revised, or deleted by this permit. All previous registrations and permits are superseded by this permit.

Enforcement Issue

There are no enforcement actions pending.

Emission Calculations

See Appendix A of this document for detailed emission calculations.

County Attainment Status

The source is located in Lake County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Attainment effective February 18, 2000, for the part of the city of East Chicago bounded by Columbus Drive on the north; the Indiana Harbor Canal on the west; 148th Street, if extended, on the south; and Euclid Avenue on the east. Unclassifiable or attainment effective November 15, 1990, for the remainder of East Chicago and Lake County.
O_3	Attainment effective May 11, 2010, for the 8-hour ozone standard.[1]
PM_{10}	Attainment effective March 11, 2003, for the cities of East Chicago, Hammond, Whiting, and Gary. Unclassifiable effective November 15, 1990, for the remainder of Lake County.
NO_2	Cannot be classified or better than national standards.
Pb	Not designated.
[1]The U. S. EPA has acknowledged in both the proposed and final rulemaking for this redesignation that the anti-backsliding provisions for the 1-hour ozone standard no longer apply as a result of the redesignation under the 8-hour ozone standard. Therefore, permits in Lake County are no longer subject to review pursuant to Emission Offset, 326 IAC 2-3. Basic nonattainment designation effective federally April 5, 2005, for PM2.5.	

(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides (NO_x) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NO_x emissions are considered when evaluating the rule applicability relating to ozone. Lake County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NO_x emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
U.S. EPA, in the Federal Register Notice 70 FR 943 dated January 5, 2005, has designated Lake County as nonattainment for $PM_{2.5}$. On March 7, 2005 the Indiana Attorney General's Office, on behalf of IDEM, filed a lawsuit with the Court of Appeals for the District of Columbia Circuit challenging U.S. EPA's designation of nonattainment areas without sufficient data. However, in order to ensure that sources are not potentially liable for a violation of the Clean Air Act, the OAQ is following the U.S. EPA's New Source Review Rule for $PM_{2.5}$ promulgated on May 8, 2008. These rules became effective on July 15, 2008. Therefore, direct $PM_{2.5}$ and SO_2 emissions were reviewed pursuant to the requirements of Nonattainment New Source Review, 326 IAC 2-1.1-5. See the State Rule Applicability – Entire Source section.

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

Fugitive Emissions

Since this source is classified as a Fossil Fuel-Fired Steam Electric Plant of more than 250 MMBtu/hr heat input, it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Unrestricted Potential Emissions

This table reflects the unrestricted potential emissions of the source.

Unrestricted Potential Emissions	
Pollutant	Tons/year
PM	113.06
PM_{10}	113.03
$PM_{2.5}$	113.02
SO_2	13.44
VOC	104.63
CO	820.06
NO_x	1,082.99

HAPs	**tons/year**
Formaldehyde	11.52
Hexane	11.25
Pb	0.011
H2SO4	1.48
Other HAPs	2.07
Total	**> 25**

Appendix A of this TSD reflects the unrestricted potential emissions of the source.

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM2.5, PM10, VOC, SO2, NOx and CO are equal to or greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit Renewal.

(b) The potential to emit (as defined in 326 IAC 2-7-1(29)) of any single HAP is equal to or greater than ten (10) tons per year and/or the potential to emit (as defined in 326 IAC 2-7-1(29)) of a combination of HAPs is equal to or greater than twenty-five (25) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

Actual Emissions

The following table shows the actual emissions as reported by the source. This information reflects the 2009 OAQ emission data.

Pollutant	Actual Emissions (tons/year)
PM	---
PM_{10}	52
$PM_{2.5}$	52
SO_2	5
VOC	34
CO	32
NO_x	80
Ammonia	---
Pb	0.01

Part 70 Permit Conditions

This source is subject to the requirements of 326 IAC 2-7, because the source met the following:

(a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.

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

Potential to Emit After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any new control equipment is considered federally enforceable only after issuance of this Part 70 permit renewal, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance of Renewal (tons/year)								
	PM	PM10*	PM2.5	SO_2	VOC	CO	NOx	Total HAPs	Worst Single HAP
GE PG7241 (FA) Combustion Turbines	68.39	68.39	68.39	11.58	24.32	243.18	161.1	19.1	7.6
COEN Duct Burners	18.47	18.47	18.47		45.16	328.5	100.8	4.29	2.05
Cooling Tower	12.27	12.27	12.27	0	0	0	0	0	0
Pave Roads	0.035	0.007	0.002	0	0	0	0	0	0

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance of Renewal (tons/year)								
	PM	PM10*	PM2.5	SO_2	VOC	CO	NOx	Total HAPs	Worst Single HAP
Cold Cleaner Degreasing Operations	0	0	0	0	1.2	0	0	0	0
Total PTE of Entire Source	**99.17**	**99.14**	**99.13**	**11.58**	**70.69**	**571.58**	**261.9**	**23.38**	**9.65**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	25	10
PSD Major Source Thresholds	100	100	--	100	100	100	100	NA	NA
Nonattainment NSR	---	---	100	--	---	---	---	NA	NA

negl. = negligible
*Under the Part 70 Permit program (40 CFR 70), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM10), not particulate matter (PM), is considered as a "regulated air pollutant".

(a) This existing stationary source is major for PSD because the emissions of at least one regulated pollutant are greater than one hundred (>100) tons per year, and it is in one of the twenty-eight (28) listed source categories.

(b) This existing source is a minor stationary source, under nonattainment new source review rules (326 IAC 2-1.1-5) since direct $PM_{2.5}$ is emitted at a rate less than 100 tons per year.

Federal Rule Applicability

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each existing pollutant-specific emission unit that meets the following criteria:

(1) has a potential to emit before controls equal to or greater than the major source threshold for the pollutant involved;

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

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to each existing emission unit and specified pollutant subject to CAM:

Emission Unit / Pollutant	Control Device Used	Emission Limitation (Y/N)	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
Duct Burner DB1 - NO_X	Y	Y	288	50.4	100	Y	N
Duct Burner DB2 - NO_X	Y	Y	288	50.4	100	Y	N

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are applicable to the Duct Burners for NO_X emissions.

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 duct burners, identified as DB1 and DB2 at this source are subject to requirements of the Acid Rain Program, therefore, these units are exempt from the requirements of 40 CFR 64 (Continuous Assurance Monitoring).

(b) The Combustion Turbines are not subject to the requirements of the Standards of Performance for Stationary Combustion Turbines, (40 CFR 60, Subpart KKKK) because they were constructed prior to February 18, 2005.

(c) The duct burners (DB1 and DB2) are subject to the Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 (40 CFR 60, Subpart Da) because the duct burners are electric utility steam generating units that are capable of combusting more than 250 MMBtu/hr heat input of fossil fuel and construction commenced after September 18, 1978. The emission unit subject to the 40 CFR 60 Subpart Da is as follows:

(1) Two (2) Heat Recovery Steam Generators (HRSG), each with a Duct Burner set (DB), each constructed in 2001:

Steam Generating Capacity:	1300 psig
Duct Burner HIC:	821 MMBtu per hour (HHV), per set
Fuel Source:	Natural Gas
Control Technology:	Selective Catalytic Reduction (SCR) System for NOx control
Steam Production Capacity:	580,000 pounds per hour, each, without DBs 1,188,000 pounds per hour, each, with DBs
Stack ID:	DB1 exhausts to stack 1 DB2 exhausts to stack 2

The duct burners are subject to the following portions of Subpart Da, which is incorporated by reference as 326 IAC 12.

(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)(1)
(13) 40 CFR 60.48Da(g)(3)
(14) 40 CFR 60.48Da(h)
(15) 40 CFR 60.48Da(i)
(16) 40 CFR 60.48Da(k)(2)(iv)
(17) 40 CFR 60.49Da(a)(2)(ii)
(18) 40 CFR 60.49Da(a)(3)
(19) 40 CFR 60.49Da(o)
(20) 40 CFR 60.50Da(a)
(21) 40 CFR 60.50Da(b)
(22) 40 CFR 60.50Da(c)(4)
(23) 40 CFR 60.50Da(d)
(24) 40 CFR 60.50Da(f)
(25) 40 CFR 60.51Da(a)

(26) 40 CFR 60.51Da(b)
(27) 40 CFR 60.51Da(c)
(28) 40 CFR 60.51Da(f)
(29) 40 CFR 60.51Da(h)
(30) 40 CFR 60.51Da(i)
(31) 40 CFR 60.51Da(j)
(32) 40 CFR 60.52Da(b)

(d) The Combustion Turbines (CT1 and CT2) and two (2) duct burners associated with the heat recovery steam generators HRSG1 and HRSG2 are subject to the Standards of Performance for Stationary Gas Turbines (40 CFR 60, Subpart GG) because they are stationary gas turbines with a heat input at peak load greater than 10 MMBtu per hour and construction commenced after October 3, 1977. The emission units subject to the 40 CFR 60 Subpart GG is as follows:

(1) Two (2) Combined-cycle Combustion Turbines (CT), each constructed in 2001:

Make/Model:	General Electric Frame 7FA (Model 7241)
Heat Input Capacity (HIC):	1,735 MMBtu per hour (HHV) @ ISO conditions, each
Electric Generating Capacity:	166 MW @ ISO conditions, each
Fuel Source:	Natural Gas
Control Technology:	Dry Low-NO_x Burners
Stack ID:	CT1 exhausts through HRSG1 to stack 1 CT2 exhausts through HRSG2 to stack 2

(2) Two (2) Heat Recovery Steam Generators (HRSG), each with a Duct Burner set (DB), each constructed in 2001:

Steam Generating Capacity:	1300 psig
Duct Burner HIC:	821 MMBtu per hour (HHV), per set
Fuel Source:	Natural Gas
Control Technology:	Selective Catalytic Reduction (SCR) System for NOx control
Steam Production Capacity:	580,000 pounds per hour, each, without DBs 1,188,000 pounds per hour, each, with DBs
Stack ID:	DB1 exhausts to stack 1 DB2 exhausts to stack 2

The turbines are subject to the following portions of Subpart GG, which is incorporated by reference as 326 IAC 12.

(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(a)(4)
(6) 40 CFR 60.332(b)
(7) 40 CFR 60.333
(8) 40 CFR 60.334(c)
(9) 40 CFR 60.334(h)(3)(i)
(10) 40 CFR 60.334(j)(1)(iii)
(11) 40 CFR 60.334(j)(5)
(12) 40 CFR 60.335(a)
(13) 40 CFR 60.335(b)(3)
(14) 40 CFR 60.335(b)(7).

(e) Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAPs)
There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14 and 40 CFR Part 61) included in the permit for this source.

(f) The Cooling Tower is not subject to the requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial Cooling Towers under 40 CFR 63, Subpart Q because the source is not operated with chromium-based water treatment chemicals.

(g) The two (2) Combined-cycle Combustion Turbines (CT) are not subject to the requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Stationary Combustion Turbines under 40 CFR 63, Subpart YYYY because the source is an area sources of HAPs.

State Rule Applicability - Entire Source

326 IAC 2-1.1-5 (Nonattainment New Source Review (NSR))
This existing source is a minor stationary source, under nonattainment new source review rules (326 IAC 2-1.1-5) since direct $PM_{2.5}$ and SO2 are emitted at a rate less than 100 tons per year.

326 IAC 2-2 (Prevention of Significant Deterioration (PSD))
This electric utility generating plant was constructed in 2000-2001 and modified in 2003 after the applicability date of this rule, 1977, and this source is in 1 of the 28 listed source categories and has potential to emit PM, PM10, PM2.5, VOC, NOX and CO greater than 100 tons per year. Therefore, this existing source is a PSD major source and the requirements of 326 IAC 2-2(PSD) are applicable to this source.

2000 -2001 Modification;

326 IAC 2-2-3 (PSD BACT: Control Technology Review Requirements)
Pursuant to PSD/CP 089-11194-00449, issued on July 20, 2000, and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the source is subject to the requirements of 326 IAC 2-2-3, Best Available Control Technologies (BACT), for the two (2) combined-cycle combustion turbines (CT) for PM, NOx and CO.

Pursuant to PSD/CP 089-11194-00449, issued July 20, 2000 and 326 IAC 2-2-3, each combustion turbine (CT1 and CT2) shall comply with the following startup and shutdown limitations:

(a) A startup is defined as the operation in the period of time from the initiation of combustion until either: the turbine reaches a minimum load of seventy percent (70%), or the instantaneous outlet SCR NO_x concentration reaches a level less than 3.0 ppmvd at 15% O_2 for a period of 5 minutes, whichever occurs earlier.

(b) A shutdown is defined as operation at less than fifty percent (50%) load and descending to flame out.

(c) A startup or shutdown period shall not exceed four (4) hours. Each turbine shall not exceed 473 hours per year for startups and 260 hours per year for shutdowns with compliance demonstrated at the end of each month.

(d) The NO_x emissions from each combustion turbine stack (stacks 1 and 2) shall not exceed 510 pounds per startup and 49 pounds per shutdown. Each combustion turbine shall not exceed 41.5 tons of NO_x per year of startup and shutdown emissions.

(e) The CO emissions from each combustion turbine stack (stacks 1 and 2) shall not exceed 1,571 pounds per startup, and 220 pounds per shutdown. Each combustion turbine (CT1 and CT2) shall not exceed 168.7 tons per year of startup and shutdown emissions.

326 IAC 2-2-4 (PSD Air quality Analysis)
Pursuant to PSD/CP 089-11194-00449, issued July 20, 2000, and 326 IAC 2-2-4, in order to ensure that the ammonia emissions from the turbines exhausts do not contribute to a degradation of air quality, the ammonia emissions from each combustion turbine stack (stacks 1 and 2) shall not exceed 10 ppm.

Operational Limitations
Pursuant to CP 089-11194-00449, issued July 20, 2000:

(a) The combined natural gas fuel usage from the duct burner sets (DB1 and DB2) shall not exceed 8,052 million standard cubic feet (MMSCF) per twelve consecutive month period with compliance determined at the end of each month.

Compliance with this limit, the PM_{10} emissions from the combustion turbines and the controlled PM_{10} emissions from the cooling tower is equivalent to source-wide PM_{10} emissions of less than 100 tons per year and will render the requirements of 326 IAC 2-2 not applicable with respect to PM_{10}.

(b) Each combustion turbine (CT1 and CT2) shall not exceed an heat input rate of 1735 MMBtu per hour (based on HHV at ISO conditions), determined on a 30-day rolling average basis. The averaging time shall only account for those periods that the respective combustion turbine is in operation.

326 IAC 2-4.1 (Hazardous Air Pollutants (HAP))
Pursuant to CP 089-11194-00449, issued July 20, 2000:

(a) The formaldehyde emissions from the combustion turbine stacks (stacks 1 and 2) shall not exceed 0.0005 pounds per MMBtu and less than 10 tons per year.

(b) The hexane emissions from the combustion turbine stacks (stacks 1 and 2) shall not exceed 0.0005 pounds per MMBtu and less than 10 tons per year.

Compliance with these limits will limit the source wide single HAP emissions to less than 10 tons per year and source wide combination of HAPs emission to less than 25 tons per year and render the requirements of 326 IAC 2-4.1 and 40 CFR 63, Subpart YYYY not applicable to these emission units.

326 IAC 2-6 (Emission Reporting)
This source is subject to 326 IAC 2-6 (Emission Reporting) because it is located in Lake County and its emissions of VOC and NOx are greater than 25 tons per year. Therefore, pursuant to 326 IAC 2-6-3(a)(1), annual reporting is required. An emission statement shall be submitted by July 1, 2011, and every year thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 5-1 (Opacity Limitations)
This source is subject to the opacity limitations specified in 326 IAC 5-1-2(2)

326 IAC 6.8 PM Limitations for Lake County
This source is subject to 326 IAC 6.8 because it is located in Lake County, its PM PTE (or limited PM PTE) is equal to or greater than 100 tons per year or actual emissions are greater than 10 tons per year. However, this source is not one of the sources specifically listed in 326 IAC 6.8-2 through 326 IAC 6.8-4. Therefore, 326 IAC 6.8-1-2(a) and (b)(3) applies.

326 IAC 6-4 (Fugitive Dust Emission Limitations)
The source is subject to the requirements of 326 IAC 6-4 because this rule applies to all sources of fugitive dust and the source maintains paved roads which are sources of fugitive dust.

326 IAC 6-5 (Fugitive Particulate Matter)
The source does not contain a facility which generates fugitive particulate emissions greater than 25 tons per year. Vehicular traffic on paved roads are the only source of fugitive particulate matter at this source which results in negligible fugitive particulate matter emissions. As a result, the requirements of 326 IAC 6-5 are not applicable to this source.

326 IAC 9 (Carbon Monoxide Emission Limitations)
The source is subject to 326 IAC 9 because it is a stationary source which emits CO and commenced operation after March 21, 1972. However, there are no specific emission limitations required by this rule because the source is not an operation listed under 326 IAC 9-1-2.

State Rule Applicability – Individual Facilities

326 IAC 3-5 (Continuous Emission Monitoring System)

(a) Pursuant to 326 IAC 3-5-1(b)(1), (b)(2) and (d)(1), and in order to comply with 326 IAC 2-2, 326 IAC 2-3, the Permittee is required to calibrate, certify, operate and maintain a continuous emission monitoring system (CEMS) for measuring O_2, NO_X and CO emissions rates from the combustion turbine stacks (stacks 1 and 2) in accordance with 326 IAC 3-5 and 40 CFR Part 60.

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

(c) In instances of CEMS downtime, the Permittee shall report the NO_X mass emissions in accordance with the procedures regulated by 40 CFR Part 75, Appendix D (Optional SO_2 Emissions Data Protocol) for fuel flow meters requirements, 40 CFR Part 75, Appendix E (Optional NO_X Emissions Estimation Protocol) for emission rate curve establishment, and Appendix G (Determination of CO_2 Emissions). NO_X mass emissions reported shall be based on the fuel-and-unit-specific NO_X emission rates ("load curve") established during the latest and most representative CEMS data.

326 IAC 6.8-1 (Particulate Matter Limitations for Lake County)
This source is subject to 326 IAC 6.8-1 because it is located in Lake County, a non-attainment area for particulate matter as listed in 326 IAC 6.8-1-1, and has the potential to emit 100 tons or more of particulate matter per year.

Pursuant to 326 IAC 6.8-1-2:

(a) The particulate matter (PM) emissions from each combustion turbine (CT1 and CT2) shall not exceed 0.03 grains per dry standard cubic foot (dscf).

(b) The duct burner sets (DB1 and DB2) are each a “fuel combustion steam generator” pursuant to 326 IAC 6.8-1-2 (b)(3). Therefore, the particulate matter (PM) emissions from each combustion turbine stack (stacks 1 and 2), when its associated duct burner is operating, shall not exceed 0.01 grains per dry standard cubic foot (dscf).

(c) Pursuant to 326 IAC 6.8-1-2, the particulate matter (PM) emissions from the induced draft cooling tower shall not exceed 0.03 grains per dry standard cubic foot (dscf).

326 IAC 6-2 (Particulate Emissions Limitations for Sources of Indirect Heating)
The emission units, identified as CT1, CT2, DB1 and DB2 are not subject to the requirements of 326 IAC 6-2 because they are not sources of indirect heating.

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)
The combined-cycle system located at this source (consisting of CT1, CT2, DB1, and DB2) is subject to the requirements of 326 IAC 7-1.1-2 because it has the potential to emit greater than 25 tons of SO_2 per year. However, pursuant to this rule, there are no specific SO_2 emission limitations for the combustion of natural gas.

326 IAC 8-1-6 (Volatile Organic Compounds - BACT)
Pursuant to PSD/CP 089-11194-00449, issued July 20, 2000, the source is subject to the requirements of 326 IAC 8-1-6 (BACT) because the VOC PTE exceeds 25 tons per year. The emission units shall comply with the following limits.

(a) When only the respective turbine is operating, the VOC emissions from each combustion turbine stack (stacks 1 and 2), shall not exceed 0.0016 pounds per MMBtu (equivalent to less than or equal to 2.8 pounds VOC per hour).

(b) The VOC emissions from each combustion turbine stack (stacks 1 and 2), when its associated duct burner set (DB1 and DB2) is operating, shall not exceed 0.0046 pounds per MMBtu (equivalent to less than or equal to 11.8 pounds VOC per hour).

(c) Good combustion practices shall be implemented to minimize VOC emissions from the combustion turbines (CT1 and CT2) and duct burner sets (DB1 and DB2).

326 IAC 8-3-2 (Cold Cleaner Operations)
The cold cleaner degreasing units are subject to 326 IAC 8-3-2 because it is a cold cleaning facility constructed after January 1, 1980.

326 IAC 8-3-5 (Cold Cleaner Degreaser Operation and Control)
The cold cleaner degreasing units are subject to 326 IAC 8-3-5 because it is a cold cleaner degreaser facility constructed after January 1, 1980.

326 IAC 21 Acid Deposition Control
326 IAC 21 incorporates by reference the provisions of 40 CFR 72 through 40 CFR 78 for the purposes of implementing an acid rain program that meets the requirements of Title IV of the Clean Air Act and to incorporate monitoring, record keeping, and reporting requirements for nitrogen oxide and sulfur dioxide emissions to demonstrate compliance with nitrogen oxides and sulfur dioxide emission reduction requirements. This source is subject to the requirements of 326 IAC 21 and has been incorporated into the permit.

326 IAC 24 Clean Air Interstate Rule (CAIR)
Pursuant to 326 IAC 24-1(a)(1), this rule applies to any fossil fuel-fired boilers serving at any time after November 15, 1990, with a nameplate capacity of more than twenty-five (25) megawatt electrical producing electricity for sale. 326 IAC 24 defines fossil fuel as natural gas, petroleum, coal, or any form of solid, liquid or gaseous fuel derived from such fuel. 326 IAC 24 defines fossil fuel-fired as a unit combusting any amount of fossil fuel in any calendar year. Therefore, the combustion turbines, identified as CT1 and CT2 are subject to the requirements of 326 IAC 24.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions; however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination

Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

The compliance determination requirements applicable to this source are as follows:

Emission Unit	Control Device	Pollutant	Frequency of Testing	Requirements
Combustion Turbine CT1 or CT2	none	PM, PM10, PM2.5 and Opacity	5 years	326 IAC 2-2-3
Combustion Turbine CT1 or CT2	none	VOC	5 years	326 IAC 2-2 and 326 IAC 8-1-6
Combustion Turbine CT1 or CT2	none	Ammonia	5 years	326 IAC 2-2-4

Note: There are no control device for particulate matter, VOCs, hexane, formaldehyde and ammonia, hence there are no monitoring conditions for these emission units in the permit for particulate matter, VOCs, hexane, formaldehyde and ammonia.

In the event significant adjustments are made to any of the burners or in the event any burners are replaced with a different type of burner, the Permittee shall perform hexane and formaldehyde testing no later than 90 days after resuming operations after such adjustment or replacement, utilizing methods approved by the Commissioner. When required due to a significant adjustment to any burner or a replacement of any burner with a different burner type, the testing shall be performed on one affected combustion turbine at maximum load, when its associated duct burners are in operation, and shall be repeated on alternating affected combustion turbine/duct burner sets.

Recommendation

The staff recommends to the Commissioner that the Part 70 Operating Permit Renewal be approved. This recommendation is based on the following facts and conditions:

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on November 17, 2010.

Conclusion

The operation of this stationary industrial steam and 545 MWe co-generation (“combined heat and power”) plant shall be subject to the conditions of the attached Part 70 Operating Permit Renewal No. 089-29885-00449.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Josiah Balogun at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 234-5257 or toll free at 1-800-451-6027 extension 4-5257.

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

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM's Guide for Citizen Participation and Permit Guide on the Internet at: www.idem.in.gov

Summary of Global Permit Changes to Section B, C and D.

Change 0: Condition C.5 **-** Fugitive Particulate Matter Emissions [326 IAC 6.8-10-3], has been deleted from the permit. The fugitive emission from the source is less than 5 tons per year.

Change 1: IDEM has made the following changes throughout the permit:

... require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)**...

...by ~~the~~ **a** "responsible official"...

...by ~~the~~ **a** responsible official...

Change 2: IDEM has added clarification to Condition B.15, Permit Term, as follows:

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

(a) ~~This permit~~ **The Part 70 Operating Permit**, T XXX-XXXXX-XXXXX, 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.

(b) ...

Change 3: There may be times when it is unnecessary for a responsible official to "certify" additional information requested by IDEM; therefore, paragraph (a) of Condition B.7, Duty to Provide Information, is revised as follows:

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 a 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) ...

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, 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,~~ **A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:**

(i) **it contains a certification by a "responsible official", as defined by 326 IAC 2-7-1 (34), and**

(ii) **the certification is** 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 Permittee may use** the attached Certification Form ~~or another form meeting the requirements of 326 IAC 2-7-4(f)~~**, or its equivalent**, with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.

(c) ~~The~~ **A** "responsible official" is defined at 326 IAC 2-7-1(34).

Clean version...

~~(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) The "responsible official" is defined at 326 IAC 2-7-1(34).~~

(a) **A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:**

(i) **it contains a certification by a "responsible official", as defined by 326 IAC 2-7-1 (34), and**

(ii) **the certification is based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.**

(b) **The Permittee may use the attached Certification Form, or its equivalent, with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.**

(c) **A "responsible official" is defined at 326 IAC 2-7-1(34).**

Change 4: The Preventive Maintenance Plan requirements have been clarified 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) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) for each facility as described in 326 IAC 1-6-3. At a minimum, the PMP shall include:~~

(a) A Preventive Maintenance Plan meets the requirements of 326 IAC 1-6-3 if it includes, at a minimum:

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

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

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

The Permittee shall implement the PMPs.

(b) If required by specific condition(s) in Section D of this permit where no PMP was previously required, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this permit or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:

(1) Identification of the individual(s) ~~(by job title or description)~~ 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 time frame specified in Section D, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

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

The PMP extension notification does not require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

(c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to ~~a violation of any~~ **an exceedance of any** limitation on emissions~~ for that unit~~. The PMPs do not require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

(d) To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

Change 5: The emergency provisions requirements have been clarified as follows:

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

(a) (b) ...

(1) - (3) ...

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, ~~within~~ **no later than** four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

...

(5) ...

~~within~~ **no later than** 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) - (C) ...

The notification which shall be submitted by the Permittee does not require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

(6) ...

(c) - (g) ...

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

Change 6: IDEM has removed the Condition B.15, Deviations from Permit Requirements and Conditions, and moved the requirements to Condition C.17, General Reporting Requirements, as follows:

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

~~(a) Deviations from any permit requirements for any deviation for which a report is specifically required under Section D (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 and Enforcement Branch, Office of Air Quality~~
~~100 North Senate Avenue~~
~~MC 61-53, IGCN 1003~~
~~Indianapolis, Indiana 46204-2251~~

~~using the attached Quarterly Deviation and Compliance Monitoring Report, or its equivalent. Notwithstanding this condition, 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.~~

Change 7: The General Reporting Requirements have been clarified as follows:

~~C.21~~**C.17** 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~~ as set out at Condition B.15 – Deviations from Permit Requirements and Conditions~~. **Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.**

(b) ~~Reports required by conditions in Section D of this permit shall be submitted to~~ **The address for report submittal is**:

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

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

~~(d) Unless otherwise specified in this permit, all reports required in Section D of this permit shall be submitted no later than thirty (30) days after the end of the reporting period. Unless otherwise specified in this permit, all reports required in Section D do require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(e)~~**(d)** 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)~~ **(e)** If the Permittee is required to comply with the recordkeeping provisions of (d) in Section C - General Record Keeping Requirements for any "project" (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(ll)) at an existing emissions unit, and the project meets the following criteria:

(1) - (2) ...

~~(g)~~ **(f)** The~~n the Permittee shall submit the~~ report for a project at an existing emissions unit no later than sixty (60) days after the end of the year~~, which~~ shall contain the following:

(1) - (3) ...

(4) Any other information that the Permittee ~~deems fit~~ **wishes** to include in this report **such as an explanation as to why the emissions differ from the preconstruction project**.

...

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

Change 8: The Permit Modification, Reopening, Revocation and Reissuance, or Termination provisions have been clarified as follows:

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

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

...

Change 9: The Permit Renewal requirements have been clarified as follows:

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

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

(b) ...

(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 reasonable deadline specified**, pursuant to 326 IAC 2-7-4(a)(2)(D),** in writing by IDEM, OAQ any additional information identified as being needed to process the application.

Change 10: The words "or notice" have been added to Condition B.19(a) as follows:

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

(a) No Part 70 permit revision **or notice** shall be required under any approved economic incentives, marketable Part 70 permits, emissions trading, and other similar programs or processes for changes that are provided for in a Part 70 permit.

(b) ...

Change 11: The Operational Flexibility provisions have been clarified as follows:

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

...

(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~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

...

Change 12: The Transfer of Ownership or Operational Control provisions have been clarified as follows:

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

...

(b) ...

The application which shall be submitted by the Permittee does require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

...

Change 13: The Opacity requirements have been clarified as follows:

C.2 Opacity [326 IAC 5-1]

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

(a) - (b) ...

Change 14: The Incineration requirements have been clarified as follows:

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

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

Change 15: The Performance Testing requirements have been clarified as follows:

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~~ **For performance testing required by this permit, a** test protocol, except as provided elsewhere in this permit, shall be submitted to:

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

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "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 **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "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. The extension request submitted by the Permittee does not require **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

Change 16: The Compliance Monitoring requirements have been clarified as follows:

C.9 Compliance Monitoring [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

~~Unless otherwise specified in this permit, for all monitoring and record keeping requirements not already legally required shall be implemented not later than ninety (90) days after permit issuance. The Permittee shall be responsible for installing any equipment described in Section D and initiating any required monitoring related to that equipment. If due to circumstances beyond its reasonable 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:~~
Unless otherwise specified in this permit, for all monitoring requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or of initial start-up, whichever is later, to begin such monitoring. If due to circumstances beyond the Permittee's control, any monitoring equipment required by this permit cannot be installed and operated no later than ninety (90) days after permit issuance or the date of initial startup, whichever is later, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

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

in writing, prior to the end of the initial ninety (90) day compliance schedule, with full justification of the reasons for the inability to meet this date.

The notification which shall be submitted by the Permittee does require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "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.

Change 17: The general requirements for Monitoring Methods were removed from Section C as follows (This provision will be included as needed in Section D of the permit.):

~~C.12 Monitoring Methods [326 IAC 3] [40 CFR 60] [40 CFR 63]~~

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

Change 18: IDEM is revising Condition C.15 as follows:

C.13 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]

Upon detecting an excursion where a response step is required by the D Section or an exceedance of a limitation in this permit:

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

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

(1) initial inspection and evaluation;

(2) recording that operations returned **or are returning** to normal without operator action (such as through response by a computerized distribution control system); or

(3) any necessary follow-up actions to return operation to ~~within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable~~ **normal or usual manner of operation**.

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

(1) - (3) ...

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

(e) The Permittee shall ~~maintain the following records:~~ **record the reasonable response steps taken.**

~~(1) monitoring data;~~

~~(2) monitor performance data, if applicable; and~~

~~(3) corrective actions taken.~~

Change 19: IDEM is revising paragraph (b) of Condition C.16 as follows:

C.14 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~~ **its** response actions to IDEM, OAQ, no later than ~~thirty (30)~~ **seventy-five (75)** days after ~~receipt~~ **the date** 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~~ **no later than** one hundred ~~twenty (120)~~ **eighty (180)** days ~~of receipt~~ **after the date** of the ~~original~~ test~~ results~~. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred ~~twenty (120)~~ **eighty (180)** days is not practicable, IDEM, OAQ may extend the retesting deadline.

(c) ...

The response action documents submitted pursuant to this condition do require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

Change 20: IDEM is revising paragraph (a) of Condition C.17 as follows:

C.15 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(b)(2), starting in 2005 and every three (3) years thereafter, the Permittee shall submit ~~by~~ **no later than** July 1 an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

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

~~(2)~~**(b)** Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(32) ("Regulated pollutant, which is used only for purposes of Section 19 of this rule") from the source, for purpose of fee assessment.

The statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue
MC 61-50, IGCN 1003
Indianapolis, Indiana 46204-2251

The emission statement does require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "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.~~

Change 21: The General Record Keeping requirements have been revised as follows:

C.16 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2] [326 IAC 2-3]

(a) ...

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

(c) - (d) ...

Change 22: The Stratospheric Ozone Protection requirements have been revised as follows:

C.18 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~~ **applicable** 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.~~

Change 23: IDEM agrees to make the following changes throughout Section D of the permit:

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

Testing shall be conducted in accordance with **the provisions of 326 IAC 3-6 (Source Sampling Procedures).** Section C - Performance Testing **contains the Permittee's obligations with regard to the performance testing required by this condition**.

If abnormal emissions are observed, the Permittee shall take reasonable response steps ~~in accordance with Section C – Response to Excursions or Exceedances~~. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps ~~in accordance with Section C – Response to Excursions or Exceedances,~~ shall be considered a deviation from this permit. **Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.**

The Permittee shall record the pressure drop across the baghouse used in conjunction with ________ at least once per day when the process is in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range of __________ inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps ~~in accordance with Section C - Response to Excursions or Exceedances~~. **Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.** A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps ~~in accordance with Section C - Response to Excursions or Exceedances~~ shall be considered a deviation from this permit.

To document **the** compliance **status** with ________, the Permittee shall ...

~~All records shall be maintained in accordance with~~ Section C - General Record Keeping Requirements~~, of this permit.~~ **contains the Permittee's obligations with regard to the record keeping required by this condition.**

These reports shall be submitted not later than thirty (30) calendar days following the end of each calendar quarter**.** ~~and in accordance with Condition~~ **Section** C - General Reporting Requirements ~~of this permit.~~ **contains the Permittee's obligations with regard to the reporting required by this condition**.

A quarterly report of the _______ to document **the** compliance **status** with _________ shall be submitted ~~to the address listed in Section C - General Reporting Requirements, of this permit,~~ using the reporting forms located at the end of this permit, or their equivalent, ~~within thirty (30) days after the end of the quarter being reported~~ not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** “responsible official” as defined by 326 IAC 2-7-1(34). **Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition**.

Change 24: The Quarterly Reports have been updated as follows:

EMERGENCY OCCURRENCE REPORT

...

☐	This is an emergency as defined in 326 IAC 2-7-1(12). • The Permittee must notify the Office of Air Quality (OAQ), ~~within~~ **no later than** four (**4**) **daytime** business hours (1-800-451-6027 or 317-233-0178, ask for Compliance and Enforcement Branch); and • The Permittee must submit notice in writing or by facsimile ~~within~~ **no later than** two (**2**) days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.

...

~~Attach a signed certification to complete this report.~~
A certification is not required for this report.

Change 25: The Quarterly Reports have been updated as follows:

Part 70 Quarterly Report

...

Attach a signed certification **that meets the requirements of 326 IAC 2-7-6(1)** to complete this report.

Change 26: The Quarterly Deviation and Compliance Monitoring Report has been updated as follows:

PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

...

This report shall be submitted quarterly based on a calendar year. Any deviation from the requirements **of this permit**, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".

...

Attach a signed certification **that meets the requirements of 326 IAC 2-7-6(1)** to complete this report.

Change 26: The PSD Minor Limit for SO2 emissions have been removed from the permit. The uncontrolled SO2 emissions are less than 100 tons per year, therefore the SO2 limits in the permit is redundant. Therefore, the limits have been removed from the permit.

~~Pursuant to SPR 089-15716-00449, issued May 2, 2003, MPR 089-12600-00449, issued December 11, 2000, and PSD/CP 089-11194-00449, issued July 20, 2000, the total combined~~ ~~SO_2 emissions from the combustion turbines (CT1 and CT2) and duct burner sets (DB1 and DB2) shall not exceed 22.8 pounds per hour and 99.8 tons per year.~~

~~Compliance with these limits will limit the SO2 emissions from the combustion turbines to less than 100 tons per year and render the requirements of 326 IAC 2-2 (PSD) not applicable to the combustion turbines for SO_2 emissions.~~

Appendix A: Emissions Calculations

Emission Summary

Source Name: Whiting Clean Energy, Inc.
Source Location: 2155 Standard Avenue, Whiting, Indiana 46394
Permit Number: T 089-29885-00449
Permit Reviewer: Josiah Balogun
Date: 01-Jun-11

Uncontrolled Potential to Emit

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	HAPs (tons/yr)
Emission Unit								
GE PG 7241 (FA) Combustion Turbines (CT1 and CT2)	68.39	68.39	68.39	13.44	24.32	244.7	507.63	26.6
COEN Duct Burners (DB1 and DB2)	32.36	32.36	32.36		79.11	575.36	575.36	
Cooling Tower	12.27	12.27	12.27	0	0	0	0	0
Pave Roads	0.035	0.007	0.002	0	0	0	0	0
Degrasing Operations	0	0	0	0	1.2	0	0	0
Total Emissions	113.06	113.03	113.02	13.44	104.63	820.06	1082.99	26.60

Limited Potential to Emit

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	HAPs (tons/yr)
Emission Unit								
GE PG 7241 (FA) Combustion Turbines (CT1 and CT2)	68.39	68.39	68.39	11.58	24.32	243.18	161.1	23.38
COEN Duct Burners (DB1 and DB2)	18.47	18.47	18.47		45.16	328.4	100.8	
Cooling Tower	12.27	12.27	12.27	0	0	0	0	0
Pave Roads	0.035	0.007	0.002	0	0	0	0	0
Cold Cleaner Degrasing Operations	0	0	0	0	1.2	0	0	0
Total Emissions	99.17	99.14	99.13	11.58	70.68	571.58	261.9	23.38

Emission Factors for Combustion Turbines and Duct Burners

Pollutant	Fuel	Emission Factor		Basis (from CP 089-11194-00449)
Combustion Turbines:				
CO	Natural Gas	0.016	lb/MMBtu	GE Data Sheet dated THIBAUBE 3/4/99; 28 lb CO/hr @ BASE 59^o
NO_X	Natural Gas	0.0334	lb/MMBtu	GE Data Sheet dated THIBAUBE 3/4/99; 58 lb NO_2/hr @ BASE 59^o
PM	Natural Gas	0.0045	lb/MMBtu	Assume that PM = PM_{10}
PM_{10}	Natural Gas	0.0045	lb/MMBtu	Stack Test Information of Similar Sized Combined Cycle facility in Pasadena, TX
$PM_{2.5}$	Natural Gas	0.0045	lb/MMBtu	Assume that $PM_{2.5}$ = PM_{10}
SO_2	Natural Gas	0.0006	lb/MMBtu	AP-42 Table 1.4-2 lb/MMscf value divided by natural gas HHV of 1020 Btu/scf
VOC	Natural Gas	0.0016	lb/MMBtu	GE Data Sheet dated THIBAUBE 3/4/99; 2.8 lb VOC/hr @ BASE 59^o
Formaldehyde	Natural Gas	0.0005	lb/MMBtu	SPR 098-15716-00449
Hexane	Natural Gas	0.0005	lb/MMBtu	SPR 098-15716-00449
H_2SO_4	Natural Gas	0.00008	lb/MMBtu	0.08 fraction of SO2 * (134 $MW_{H2SO4 + 2H2O}$ / 64 MW_{SO2})
Pb	Natural Gas	4.90E-07	lb/MMBtu	AP-42 Table 1.4-2 lb/MMscf value divided by natural gas HHV of 1020 Btu/scf
Duct Burners:				
CO	Natural Gas	0.08	lb/MMBtu	AAL Borg Letter dated 11/22/99 -- 65.7 lb/hr
NO_X	Natural Gas	0.08	lb/MMBtu	AAL Borg Letter dated 11/22/99 -- 65.7 lb/hr
PM	Natural Gas	0.0045	lb/MMBtu	Assume that PM = PM_{10}
PM_{10}	Natural Gas	0.0045	lb/MMBtu	Stack Test Information of Similar Sized Combined Cycle facility in Pasadena, TX
$PM_{2.5}$	Natural Gas	0.0045	lb/MMBtu	Assume that $PM_{2.5}$ = PM_{10}
SO_2	Natural Gas	0.0006	lb/MMBtu	AP-42 Table 1.4-2 lb/MMscf value divided by natural gas HHV of 1020 Btu/scf
VOC	Natural Gas	0.011	lb/MMBtu	Forney's Letter dated 11/22/99 -- 0.011 lb/MMBtu HHV nonmethane/ethane VOC
Formaldehyde	Natural Gas	0.0005	lb/MMBtu	SPR 098-15716-00449
Hexane	Natural Gas	0.0005	lb/MMBtu	SPR 098-15716-00449
H_2SO_4	Natural Gas	3.66E-05	lb/MMBtu	AP-42 Table 1.3-1 (5.7S/157S) ratio of SO_2 * (98 MW_{H2SO4} / 80 MW_{SO3})
Pb	Natural Gas	4.90E-07	lb/MMBtu	AP-42 Table 1.4-2 lb/MMscf value divided by natural gas HHV of 1020 Btu/scf

Combustion Turbine and Duct Burner Potential-To-Emit Calculations

Pollutant	Calculations (from CP 089-11194-00449)											
GE PG7241(FA) Combustion Turbines					**lbs/hr**				**tons/yr/CT**			**tons/yr**
CO	1735 MMBtu/hr	x	0.016 lb/MMBtu	=	27.8	x 8760 hrs/yr	/ 2000 lbs/ton	=	122	x 2 CTs	=	243.18
NOx	1735 MMBtu/hr	x	0.0334 lb/MMBtu	=	57.9	x 8760 hrs/yr	/ 2000 lbs/ton	=	253.8	x 2 CTs	=	507.63
PM	1735 MMBtu/hr	x	0.0045 lb/MMBtu	=	7.8	x 8760 hrs/yr	/ 2000 lbs/ton	=	34.2	x 2 CTs	=	68.39
PM_{10}	1735 MMBtu/hr	x	0.0045 lb/MMBtu	=	7.8	x 8760 hrs/yr	/ 2000 lbs/ton	=	34.2	x 2 CTs	=	68.39
$PM_{2.5}$	1735 MMBtu/hr	x	0.0045 lb/MMBtu	=	7.8	x 8760 hrs/yr	/ 2000 lbs/ton	=	34.2	x 2 CTs	=	68.39
SO_2	1735 MMBtu/hr	x	0.0006 lb/MMBtu	=	1.04	x 8760 hrs/yr	/ 2000 lbs/ton	=	4.56	x 2 CTs	=	9.12
VOC	1735 MMBtu/hr	x	0.0016 lb/MMBtu	=	2.78	x 8760 hrs/yr	/ 2000 lbs/ton	=	12.2	x 2 CTs	=	24.32
Formaldehyde	1735 MMBtu/hr	x	0.0005 lb/MMBtu	=	0.87	x 8760 hrs/yr	/ 2000 lbs/ton	=	3.8	x 2 CTs	=	7.60
Hexane	1735 MMBtu/hr	x	0.0005 lb/MMBtu	=	0.87	x 8760 hrs/yr	/ 2000 lbs/ton	=	3.8	x 2 CTs	=	7.60
H_2SO_4	1735 MMBtu/hr	x	0.00008 lb/MMBtu	=	0.139	x 8760 hrs/yr	/ 2000 lbs/ton	=	0.61	x 2 CTs	=	1.22
Pb	1735 MMBtu/hr	x	4.9E-07 lb/MMBtu	=	0.0009	x 8760 hrs/yr	/ 2000 lbs/ton	=	0.0037	x 2 CTs	=	0.0074
COEN Duct Burners					**lbs/hr**				**tons/yr/DB**			**tons/yr**
CO	821 MMBtu/hr	x	0.08 lb/MMBtu	=	65.7	x 8760 hrs/yr	/ 2000 lbs/ton	=	288	x 2 CTs	=	575.36
NOx	821 MMBtu/hr	x	0.08 lb/MMBtu	=	65.7	x 8760 hrs/yr	/ 2000 lbs/ton	=	288	x 2 CTs	=	575.36
PM	821 MMBtu/hr	x	0.0045 lb/MMBtu	=	3.69	x 8760 hrs/yr	/ 2000 lbs/ton	=	16.2	x 2 CTs	=	32.36
PM_{10}	821 MMBtu/hr	x	0.0045 lb/MMBtu	=	3.69	x 8760 hrs/yr	/ 2000 lbs/ton	=	16.2	x 2 CTs	=	32.36
$PM_{2.5}$	821 MMBtu/hr	x	0.0045 lb/MMBtu	=	3.69	x 8760 hrs/yr	/ 2000 lbs/ton	=	16.2	x 2 CTs	=	32.36
SO_2	821 MMBtu/hr	x	0.0006 lb/MMBtu	=	0.49	x 8760 hrs/yr	/ 2000 lbs/ton	=	2.16	x 2 CTs	=	4.32
VOC	821 MMBtu/hr	x	0.011 lb/MMBtu	=	9.0	x 8760 hrs/yr	/ 2000 lbs/ton	=	39.6	x 2 CTs	=	79.11
Formaldehyde	821 MMBtu/hr	x	0.0005 lb/MMBtu	=	0.4	x 8760 hrs/yr	/ 2000 lbs/ton	=	1.8	x 2 CTs	=	3.60
Hexane	821 MMBtu/hr	x	0.0005 lb/MMBtu	=	0.4	x 8760 hrs/yr	/ 2000 lbs/ton	=	1.8	x 2 CTs	=	3.60
H_2SO_4	821 MMBtu/hr	x	0.0000366 lb/MMBtu	=	0.030	x 8760 hrs/yr	/ 2000 lbs/ton	=	0.132	x 2 CTs	=	0.26
Pb	821 MMBtu/hr	x	4.9E-07 lb/MMBtu	=	0.0004	x 8760 hrs/yr	/ 2000 lbs/ton	=	0.0018	x 2 CTs	=	0.0035

Combustion Turbine and Duct Burner Potential-To-Emit Calculations for Regulated Pollutants

Pollutant	Calculations (from CP 089-11194-00449)														
GE PG7241(FA) Combustion Turbines								**lbs/hr**				**tons/yr/CT**			**tons/yr**
CO	1735 MMBtu/hr	x	0.016 lb/MMBtu	x			=	27.8	x 8760 hrs/yr	/ 2000 lbs/ton	=	122	x 2 CTs	=	243.18
NO_X	1735 MMBtu/hr	x	0.0334 lb/MMBtu	x	0.331	SCR NOx Control Fraction (CT Only)	=	19.2	x 3760 hrs/yr	/ 2000 lbs/ton	=	36.1	x 2 CTs	=	72.12
	1735 MMBtu/hr	x	0.0334 lb/MMBtu	x	0.307	CT + DB	=	17.8	x 5000 hrs/yr	/ 2000 lbs/ton	=	44.5	x 2 CTs	=	88.95
PM	1735 MMBtu/hr	x	0.0045 lb/MMBtu	x			=	7.81	x 8760 hrs/yr	/ 2000 lbs/ton	=	34.2	x 2 CTs	=	68.39
PM_{10}	1735 MMBtu/hr	x	0.0045 lb/MMBtu	x			=	7.81	x 8760 hrs/yr	/ 2000 lbs/ton	=	34.2	x 2 CTs	=	68.39
$PM_{2.5}$	1735 MMBtu/hr	x	0.0045 lb/MMBtu	x			=	7.81	x 8760 hrs/yr	/ 2000 lbs/ton	=	34.2	x 2 CTs	=	68.39
SO_2	1735 MMBtu/hr	x	0.0006 lb/MMBtu	x			=	1.04	x 8760 hrs/yr	/ 2000 lbs/ton	=	4.56	x 2 CTs	=	9.12
VOC	1735 MMBtu/hr	x	0.0016 lb/MMBtu	x			=	2.78	x 8760 hrs/yr	/ 2000 lbs/ton	=	12.2	x 2 CTs	=	24.32
Formaldehyde	1735 MMBtu/hr	x	0.0005 lb/MMBtu	x			=	0.87	x 8760 hrs/yr	/ 2000 lbs/ton	=	3.8	x 2 CTs	=	7.60
Hexane	1735 MMBtu/hr	x	0.0005 lb/MMBtu	x			=	0.87	x 8760 hrs/yr	/ 2000 lbs/ton	=	3.8	x 2 CTs	=	7.60
H_2SO_4	1735 MMBtu/hr	x	0.00008 lb/MMBtu	x		[1] Due to higher SCR temp during duct firing	=	0.139	x 8760 hrs/yr	/ 2000 lbs/ton	=	0.61	x 2 CTs	=	1.22
Pb	1735 MMBtu/hr	x	4.9E-07 lb/MMBtu	x			=	0.0009	x 8760 hrs/yr	/ 2000 lbs/ton	=	0.0037	x 2 CTs	=	0.0074
COEN Duct Burners								**lbs/hr**				**tons/yr/DB**			**tons/yr**
CO	821 MMBtu/hr	x	0.08 lb/MMBtu				=	65.68	x 5000 hrs/yr	/ 2000 lbs/ton	=	164	x 2 CTs	=	328.40
NO_X	821 MMBtu/hr	x	0.08 lb/MMBtu	x	0.307	CT + DB	=	20.2	x 5000 hrs/yr	/ 2000 lbs/ton	=	50.4	x 2 CTs	=	100.82
PM	821 MMBtu/hr	x	0.0045 lb/MMBtu	x			=	3.6945	x 5000 hrs/yr	/ 2000 lbs/ton	=	9.2	x 2 CTs	=	18.47
PM_{10}	821 MMBtu/hr	x	0.0045 lb/MMBtu	x			=	3.6945	x 5000 hrs/yr	/ 2000 lbs/ton	=	9.2	x 2 CTs	=	18.47
$PM_{2.5}$	821 MMBtu/hr	x	0.0045 lb/MMBtu	x			=	3.6945	x 5000 hrs/yr	/ 2000 lbs/ton	=	9.2	x 2 CTs	=	18.47
SO_2	821 MMBtu/hr	x	0.0006 lb/MMBtu	x			=	0.49	x 5000 hrs/yr	/ 2000 lbs/ton	=	1.23	x 2 CTs	=	2.46
VOC	821 MMBtu/hr	x	0.011 lb/MMBtu	x			=	9.0	x 5000 hrs/yr	/ 2000 lbs/ton	=	22.6	x 2 CTs	=	45.16
Formaldehyde	821 MMBtu/hr	x	0.0005 lb/MMBtu	x			=	0.4	x 5000 hrs/yr	/ 2000 lbs/ton	=	1.0	x 2 CTs	=	2.05
Hexane	821 MMBtu/hr	x	0.0005 lb/MMBtu	x			=	0.4	x 5000 hrs/yr	/ 2000 lbs/ton	=	1.0	x 2 CTs	=	2.05
H_2SO_4	821 MMBtu/hr	x	0.0000366 lb/MMBtu	x			=	0.030	x 5000 hrs/yr	/ 2000 lbs/ton	=	0.075	x 2 CTs	=	0.15
Pb	821 MMBtu/hr	x	4.9E-07 lb/MMBtu	x			=	0.00040229	x 5000 hrs/yr	/ 2000 lbs/ton	=	0.0010	x 2 CTs	=	0.0020

NOTE: The OAQ evaluated and approved the emission calculations performed by the company for converting "ppm" BACT emission rates for CO and NO_X to "pound/hour" potential emission rates. These calculations have been included at the end of this section.
The limited PTE is based on 5000 hr/yr which is equivalent to the consumption of 8,052 MMSCF/yr.

Startup/Shutdown Emissions

There are more combustion pollutant emissions (CO and NO_X generated during startup/shutdown operations than during normal operation.
Therefore, these emissions must be evaluated as part of the potential emissions generated from the source.
The following calculations were performed for the startup/shutdown operations:

Parameter	Value	Reference/Calculations
Number Startup/Shutdown/yr	60 startup/shutdown/year	Scheduled Operation
NO_X Emissions/Startup/Shutdown	120 lbs/startup/shutdown	GE Vendor Information
CO Emissions/Startup/Shutdown	32 lbs/startup/shutdown	GE Vendor Information
Startup/Shutdown NO_X Emissions	3.6 tons/year	
Startup/Shutdown CO Emissions	0.96 tons/year	

Combustion Turbine and Duct Burner Potential-To-Emit Calculations for HAPs

HAP	Combustion Turbine (CT)			Duct Burner (DB)				CT + DB		2 CTs + 2 DBs	
	lb/MMscf	lb/hr	ton/yr	lb/MMscf	lb/hr	ton/yr @ 8760 hr/yr	ton/yr after control **	ton/yr before control	ton/yr after control **	ton/yr before control	ton/yr after control **
Acetaldehyde (1)	0.0686	0.12	0.51	No Data	-	-	-	0.511	0.511	1.02	1.02
Acrolein (1)	0.0237	0.04	0.18	No Data	-	-	-	0.177	0.177	0.353	0.353
Benzene (1)	0.0136	0.02	0.10	0.0021	0.002	0.007	0.004	0.109	0.106	0.217	0.211
1,3 Butadiene (1)	0.000127	0.0002	0.0009	No Data	-	-	-	0.001	0.001	0.002	0.002
Dichlorobenzene (2)	0.0012	0.002	0.009	0.0012	0.001	0.004	0.002	0.013	0.011	0.026	0.023
Ethylbenzene (1)	0.0179	0.030	0.133	No Data	-	-	-	0.133	0.133	0.267	0.267
Formaldehyde (3)	0.525	0.893	3.911	0.525	0.423	1.851	1.057	5.76	4.968	11.52	9.94
Hexane (3)	0.525	0.893	3.91	0.525	0.42	1.85	1.057	5.76	4.968	11.52	9.94
Naphthalene (1)	0.00166	0.003	0.012	0.0006	0.0005	0.002	0.001	0.015	0.014	0.029	0.027
PAHs (1)	0.00066	0.001	0.005	No Data	-	-	-	0.005	0.005	0.010	0.010
Toluene (1)	0.071	0.121	0.529	0.0034	0.003	0.012	0.007	0.541	0.536	1.08	1.07
Xylene (1)	0.0261	0.044	0.194	No Data	-	-	-	0.194	0.194	0.389	0.389
Arsenic (2)	0.0002	0.000	0.001	0.0002	0.0002	0.001	0.000	0.002	0.002	0.004	0.004
Beryllium (2)	0.000012	2.04118E-05	8.94035E-05	0.000012	0.00001	0.00004	0.000	0.0001	0.0001	0.000	0.000
Cadmium (2)	0.0011	0.002	0.008	0.0011	0.001	0.004	0.002	0.012	0.010	0.024	0.021
Chromium (2)	0.0014	0.002	0.010	0.0014	0.001	0.005	0.003	0.015	0.013	0.031	0.026
Lead (2)	0.0005	0.0009	0.004	0.0005	0.0004	0.002	0.001	0.005	0.005	0.011	0.009
Manganese (2)	0.00038	0.0006	0.003	0.00038	0.0003	0.001	0.001	0.004	0.004	0.008	0.007
Mercury (2)	0.00026	0.0004	0.002	0.00026	0.0002	0.001	0.001	0.003	0.002	0.006	0.005
Molybdenum (2)	0.0011	0.002	0.008	0.0011	0.001	0.004	0.002	0.012	0.010	0.024	0.021
Nickel (2)	0.0021	0.004	0.016	0.0021	0.002	0.007	0.004	0.023	0.020	0.046	0.040
Selenium (2)	0.000045	7.65441E-05	0.0003	0.000045	0.00004	0.0002	0.000	0.0005	0.0004	0.001	0.001
	Total HAP Potential to Emit		**9.55**			**3.75**		**13.30**		**26.60**	
otal HAP Potential to Emit (after controls limits)			**9.55**				**2.14**		**11.69**		**23.38**

NOTE: ** Pursuant to PSD/EO CP 089-11194-00449, issued July 20, 2000, the Duct Burners are limited to 8052 MMSCF per year.
(1) California Air Toxic Emission Factors (CATEF) Version 1.2, June 1998
(2) Compilation of Ar Pollutant Emission Factors Jan 1995, Table 1.4-3 and Table 1.4-4
(3) Pursuant to SPR 098-15716-00449, issued May 2, 2003, the formaldehyde and hexane emissions shall not exceed 0.0005 lb/MMBtu each (equivalent to 0.51 lb/MMSCF).

NOTE: The OAQ reviewed and accepted the emission factor data presented by the company. According to the company, the CATEF data was used for three reasons. First, the CATEF data contained emission factors for pollutants found in Form Y that AP-42 data did not address: acetaldehyde, acrolein, butadiene, ethylbenzene, polyorganic material, and zylenes. Secondly, CATEF data was used instead of AP-42 data because the CATEF emssion factors were higher than the AP-42 emission factors for benzene, formaldehyde, napthalene, and toluene. Thirdly, the CATEF data was used for hexane instead of AP-42 data because the AP-42 emission factor for hexane is several orders of magnitude greater than the other HAP emission factors and the AP-42 emission factor is not considered representative of anticipated emissions bsed on recent GE turbine emission tests for similar CTs.

Cooling Tower Emissions

Parameter	Value	Units	Notes
Flow of Water Through Tower =	160,000	gpm	Cooling Tower Drift Losses
	21,390	CFM	water flow
Water, specific gravity @ 60 F =	8.34	lb/gal	
Cooling Water Flow Rate, lb/hr =	80,064,000	lb/hr flow	160,000 gpm x 8.34 lb/gal * 60 min/hr
			AP-42 Guidance, Section 13.4, Wet Cooling Towers
Total Dissolved Solids (TDS) =	3,500	ppmw	per Amoco Corporation
Cooling Water TDS Fraction =	0.0035	lb TDS/lb water	3500 ppm / 106 lb/ppm
	280,224	lb TDS/hr flow	
Drift Losses (% Cooling Water) =	0.0010	percent	Vendor Information
Liquid Drift Losses =	801	lb/hr	lb/hr cooling water flow x 0.001%/100
Solids Drift Losses =	2.80	lb/hr	lb/hr liquid drift losses x Cooling Water TDS fraction
$PM/PM_{10}/PM_{2.5}$ Emissions:	**12.27**	**tpy**	

NOTE:
The cooling tower emissions are calculated using cooling tower water circulation rate and a drift loss emission factor provided by the mist eliminator vendor. The calculation equation is from AP-42, Section 13.4-3 as follows:

"…a conservatively high PM-10 emission factor can be obtained by (a) multiplying the total liquid drift factor by the total dissolved solids (TDS) fraction in the circulating water and (b) assuming that, once the water evaporates, all remaining solid particules are within the PM-10 size range."

No emission of VOC are expected because the cooling water will not contact equipment in VOC service.

E = D*S/1E6
PTE = E /1000 * Q * 1 ton/ 2000 lbs * 8760 hr/yr * 60 min / hr

where E = emission factor (lb/10^3 gal) = 0.0002919
D = Total Liquid Drift (%) = **0.001**
D = Total Liquid Drift (lb/10^3 gal) = 0.0834
S = Total Dissolved Solids (ppm) = **3500**
Q = Circulating Water Flow (gal/min) = **160,000**

Conversion Calculations (from CP 089-11194-00449)

The following calculations were performed to determine the pound per hour emission rate of combustion emissions (NO_x and CO) from the combustion turbines and duct burners that were guaranteed by a ppm emission rate:

1. Combustion Turbine Input Parameters

ppm = ppmvd @ actual exhaust O_2 (dry)
Exhaust Gas (EG) Flowrate (dscf/min) is @ 25°C (68°C)
MW of EG = 28.406
CT Flowrate = 3,471,000 pounds/hr (total or wet) based on GE Data Sheet @ baseload ISO conditions

	EG - Composition Volume %	MW lb/lb-mole	Weight lb/lb-mole EG
AR	0.89%	39.95	0.356
N_2	74.40%	28.01	20.85
O_2	12.40%	32	3.97
CO_2	3.89%	44	1.71
H_2O	8.42%	18.02	1.52

Molar Flowrate = CT Flowrate / MW of EG
= 122,192 lb-mol/hr EG

359 ft^3/lb-mol @ 0°C

EG Flowrate (wet @ 0°C) = Molar Flowrate (lb-mol/hr) x 359 ft^3/lb-mol @ 0°C x hr / 60 min/hr
= 731,118 ft^3/min

EG Flowrate (dry @ 0°C) = EG Flowrate (wet @ 0°C) x (1 - 0.0842)
= 669,558 ft^3/min

EG Flowrate (dry @ 25°C) = EG Flowrate (dry @ 0°C) x ((273 + 25) / 273)
= 730,873 ft^3/min

2. NO_X Emissions from the Combustion Turbines

NO_X Limit = 3.0 ppmvd @ 15% O_2 (must convert to actual O_2)
12.40% = Actual % O_2 on a wet basis (GE Data Sheet)
13.54% = Actual % O_2 on a dry basis (GE Data Sheet)

Actual ppm @ Actual %O_2 = 3.0 ppm x ((21% O_2 in air - (Actual % O_2 on a dry basis)) / (21% O_2 in air - 15% O_2 in EG))
= 3.73 ppmvd

NO_X Emission Rate per Turbine = Actual ppm @ 15% O_2 x (1 lbs NO_X/ft^3 / 8.375x10^6 ppm NO_X) x EG Flowrate (wet @ 0°C) x (60 min/hr)
= 19.5 lb/hr

NO_X Emission Rate per Turbine = 19.5 lbs/hr x ton/2000 lbs x 8760 hrs/yr
= 85.6 ton/yr

3. CO Emissions from the Combustion Turbines

CO Limit = 9.0 ppmvd @ 15% O_2 (must convert to actual O_2)

CO Emission Rate per Turbine = Actual ppm @ 15% O^2 x (1 lb CO/ft^3 / 1.38x10^7 ppm CO) x EG Flowrate (wet @ 0°C) x (60 min/hr)
= 28.6 lb/hr

CO Emission Rate per Turbine = 28.6 lbs/hr x ton/2000 lbs x 8760 hrs/yr
= 125.3 ton/yr

4. Input Parameters for Combustion Turbines and Duct Burners

Duct Burner Heat In = 821 MMBtu/hr
Natural Gas Heat Value = 1,020 Btu/ft^3

Molar Flowrate of Duct Burner = (Duct Burner Heat In (MMBtu/hr) x 10^6 Btu/MMBtu) / (NG Heating Value (Btu/ft^3) / 385.3 ft^3 @ 25°C/lb-mole)
= 2,089 lb-mol NG/hr

If we assume NG is CH4 for purpose of calculation, then the following reaction takes place:

CH_4 + 2 O_2 ---------> CO_2 + 2 H_2O

This says that for every mole of CH_4 we consume, 2 moles of O_2 in the CT exhaust gas and produce 3 moles of product gases. The molar addition to the exhaust flow is therefore 1:1. But, 2 moles of water produced.
Therefore, the following additional flow is added to the combustion turbine exhaust as a result of the duct burner:

Exhaust Flowrate of Duct Burner = Molar Flowrate of Duct Burner (lb-mole/hr) x hr/60 min x 385.3 ft^3/lb-mole
= 13,415 ft^3/min of additional wet exhaust

Because there are 2 moles of H_2O produced: 13,419 ft3/min of additional wet exhaust - 2(13,419 ft3/min of H_2O in exhaust)
= -13,415 ft^3/min

Exhaust of CT and DB (dry @ 25°C) = EG Flowrate (dry @ 25°C) - Exhaust Flowrate of Duct Burner
= 717,458 ft^3/min

EG from Combustion Turbine (wet) = 122,192 lb-mol/hr EG
Actual % O_2 on a wet basis = 12.40%

Molar O_2 Rate = Actual % O2 on a wet basis / 100 x EG from Combustion Turbine (wet)
= 15,152 lb-mol/hr

DB O_2 Reduction = 2 mol x Molar Flowrate of Duct Burner
= 4,178 lb-mol/hr

O_2 in EG after DB = Molar O_2 Rate - DB O_2 Reduction
= 10,974 lb-mol/hr

Total Exhaust Gas = EG from Combustion Turbine + EG from Duct Burner
= 124,282 lb-mol/hr

Moisture in Combustion Turbine and Duct Burner:
CT Moisture = EG from Combustion Turbine (wet) x Actual % H_2O
= 10,289 lb-mol/hr

DB Moisture = 2 mol x Molar Flowrate of Duct Burner
= 4,178 lb-mol/hr

Total Moisture = CT Moisture + DB Moisture
= 14,467 lb-mol/hr

Total Exhaust Gas (dry) = Total Exhaust Gas (wet) - Total Moisture
= 109,815 lb-mol/hr

Actual % O_2 (dry) = O_2 in EG after DB / Total Exhaust Gas (dry)
= 9.99%

5. NOx Emissions from the Combustion Turbines and Duct Burners

Actual ppm @ Actual %O_2 = 3.0 ppm x ((21% O_2 in air - (Actual %O_2 (dry))) / (21% O_2 in air - 15% O_2 in EG))
= 5.50 ppmvd

NOx Emission Rate per Turbine and Duct Burner = Actual ppm @ Actual % O_2 x (1 lbs NOx/ft^3 / 8.375x10^6 ppm NOx) x Exhaust of CT and DB (dry @ 25°C) x (60 min/hr)
= 28.3 lb/hr
= 124 ton/yr

6. CO Emissions from the Combustion Turbines and Duct Burners

CO Emission Rate of Combustion Turbine (from "3" above) =
= 28.6 lb/hr

Rated Capacity of each Duct Burner = 821 MMBtu/hr
CO Emission Factor = 0.08 lb CO/MMBtu (vendor guarantee))

CO Emission Rate per Duct Burner = Rated Capacity (MMBtu/hr) x CO Emission Factor (lb/MMBtu)
= 65.7 lb/hr

CO Emission Rate per Turbine and Duct Burner =
= 94.3 lb/hr

Fugitive Emissions from Paved Roads

Maximum Vehicular Speed: 20 mph
Average Distance of Haul: 1 miles
Weighted Average Gross Weight: 2 tons

Vehicle Type	No. of One Way Trips per Hour	Weight (tons)
passenger	0.833	2
total	0.833	

Calculations: source: AP-42, chapter 13.2.1, p. 13.2.1-6.

$E = k\,(sL)^{0.91} \times W^{1.02}$

E = Emission factor (lbs/vehicle miles traveled(VMT))
k = 0.011 particle size multiplier for PM
0.0022 particle size multiplier for PM_{10}
0.00054 particle size multiplier for $PM_{2.5}$
sL 0.4 road surface silt content (g/m^2)
W 2 weighted average vehicle weight (tons)

VMT= 7,297 (miles/yr)

PM

E = 0.0097 lbs/VMT
Potential PM Emissions (ton/yr) = Emission factor (lbs/VMT) * VMT / 2000 (lbs/ton)
Potential PM Emissions (ton/yr) = **0.035 tpy**

PM_{10}

E = 0.0019 lbs/VMT
Potential PM_{10} Emissions (ton/yr) = Emission factor (lbs/VMT) * VMT / 2000 (lbs/ton)
Potential PM_{10} Emissions (ton/yr) = **0.007 tpy**

$PM_{2.5}$

E = 0.0005 lbs/VMT
Potential $PM_{2.5}$ Emissions (ton/yr) = Emission factor (lbs/VMT) * VMT / 2000 (lbs/ton)
Potential $PM_{2.5}$ Emissions (ton/yr) = **0.002 tpy**

Cold Cleaner Degreasing Operations

Solvent used:	Mirachem® 750 Low Foam Cleaner / Degreaser	
S.G.:	0.995	
Density:	8.2983	lb/gal
Total solvent usage:	145	gal/12 months
	1,203.25	lb/12 months
	0.60	ton/12 months
No. of Units:	2	
Emission Rate:	0.08	lb VOC/hr/m^2/unit
	2000	lb VOC/ton solvent
PTE VOC:	**1.20**	**ton/yr**

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

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

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Richard Moroney
Whiting Clean Energy, Inc.
2155 Standard Ave
Whiting, IN 46364

DATE: August 19, 2011

FROM: Matt Stuckey, Branch Chief
Permits Branch
Office of Air Quality

SUBJECT: Final Decision
Part 70 Operating Permit Renewal
089-29885-00449

Enclosed is the final decision and supporting materials for the air permit application referenced above. Please note that this packet contains the original, signed, permit documents.

The final decision is being sent to you because our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person.

A copy of the final decision and supporting materials has also been sent via standard mail to:
Kenard Taylor – Mostardi Platt Environmental
OAQ Permits Branch Interested Parties List

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Final Applicant Cover letter.dot 11/30/07

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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August 19, 2011

TO: Whiting Public Library

From: Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: Whiting Clean Energy, Inc.
Permit Number: 089-29885-00449

You previously received information to make available to the public during the public comment period of a draft permit. Enclosed is a copy of the final decision and supporting materials for the same project. Please place the enclosed information along with the information you previously received. To ensure that your patrons have ample opportunity to review the enclosed permit, **we ask that you retain this document for at least 60 days.**

The applicant is responsible for placing a copy of the application in your library. If the permit application is not on file, or if you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185.

Enclosures
Final Library.dot 11/30/07

Mail Code 61-53

IDEM Staff	GHOTOPP 8/19/2011 Whiting Clean Energy, Inc. 089-29885-00449 Final			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	►	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Richard Moroney Whiting Clean Energy, Inc. 2155 Standard Ave Whiting IN 46364-2201 (Source CAATS) via confirmed delivery									
2		East Chicago City Council 4525 Indianapolis Blvd East Chicago IN 46312 *(Local Official)*									
3		Gary - Hobart Water Corp 650 Madison St, P.O. Box M486 Gary IN 46401-0486 *(Affected Party)*									
4		Lake County Health Department-Gary 1145 W. 5th Ave Gary IN 46402-1795 *(Health Department)*									
5		WJOB / WZVN Radio 6405 Olcott Ave Hammond IN 46320 *(Affected Party)*									
6		Laurence A. McHugh Barnes & Thornburg 100 North Michigan South Bend IN 46601-1632 *(Affected Party)*									
7		Shawn Sobocinski 3229 E. Atlanta Court Portage IN 46368 *(Affected Party)*									
8		Ms. Carolyn Marsh Lake Michigan Calumet Advisory Council 1804 Oliver St Whiting IN 46394-1725 *(Affected Party)*									
9		Whiting City Council and Mayors Office 1143 119th St Whiting IN 46394 *(Local Official)*									
10		Mark Coleman 9 Locust Place Ogden Dunes IN 46368 *(Affected Party)*									
11		Mr. Chris Hernandez Pipefitters Association, Local Union 597 8762 Louisiana St., Suite G Merrillville IN 46410 *(Affected Party)*									
12		Craig Hogarth 7901 West Morris Street Indianapolis IN 46231 *(Affected Party)*									
13		Whiting Public Library 1735 Oliver St Whiting IN 46394-1794 (Library)									
14		Lake County Commissioners 2293 N. Main St, Building A 3rd Floor Crown Point IN 46307 *(Local Official)*									
15		Anthony Copeland 2006 E. 140th Street East Chicago IN 46312 *(Affected Party)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.
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Name and address of Sender	►	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee / Remarks
1		Barbara G. Perez 506 Lilac Street East Chicago IN 46312 (Affected Party)									
2		Mr. Robert Garcia 3733 Parrish Avenue East Chicago IN 46312 *(Affected Party)*									
3		Ms. Karen Kroczek 8212 Madison Ave Munster IN 46321-1627 *(Affected Party)*									
4		Calumet Township Trustee 31 E 5th Avenue Gary IN 46402 *(Affected Party)*									
5		Joseph Hero 11723 S Oakridge Drive St. John IN 46373 *(Affected Party)*									
6		Gary City Council 401 Broadway # 209 Gary IN 46402 *(Local Official)*									
7		Mr. Larry Davis 268 South, 600 West Hebron IN 46341 *(Affected Party)*									
8		Gitte Laasby Post Tribune 1433 E. 83rd Ave Merrillville IN 46410 *(Affected Party)*									
9		Susan Severtson City of Gary Law Dept. 401 Broadway 4th Floor Gary IN 46402 *(Local Official)*									
10		Mark Zeltwanger 26545 CR 52 Nappanee IN 46550 *(Affected Party)*									
11		Kenard Taylor Mostardi Platt Environmental 1080 Breuckman Drive Crown Point IN 46307 *(Consultant)*									
12											
13											
14											
15											

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