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: March 1, 2010

RE: Duke Energy Indiana, Inc - Edwardsport Generating Station / 083-28683-00003

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 13-17-3-4 and 326 IAC 2, this permit modification 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 13-15-7-3 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 Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204, **within eighteen (18) days of the mailing of this notice**. 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 a Title V operating permit 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
FNTV-PMOD.doc 3/27/08

IDEM

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Mr. Mack Sims
Duke Energy Indiana - Edwardsport Generating Station
15424 East State Road 358
Edwardsport, IN 47528

March 1, 2010

Re: 083-28683-00003
Significant Source Modification to
Part 70 No.: T 083-7243-00003

Dear Mr. Sims:

Duke Energy Indiana - Edwardsport Generating Station was issued a Part 70 Operating Permit on August 10, 2004 for an electric utility generating station. A letter requesting changes to this permit was received on November 23, 2009. Pursuant to 326 IAC 2-7-10.5 the revised PSD BACT is established for the following emission units:.

(a) Coal receiving and handling system using enclosed conveyors consisting of the following equipments:

(1) Coal receiving and handling system, to be permitted in 2010, except the truck or railcar receiving and unloading station permitted in 2008, using enclosed conveyors consisting of the following equipment:

(A) 1200 ton per hour enclosed coal conveyor with particulate emissions from drop point to active coal pile stacking tube controlled by an insertable dust filter, exhausting to Stack S-1D.

(B) One (1) 1800 ton per hour reclaim tunnel, using two (2) 900 tons per hour conveyors with enclosed drop points and particulate matter controlled by a baghouse and exhausting to Stack S-2A.

(C) Two (2) 900 ton per hour enclosed coal conveyors with particulate matter from enclosed drop points controlled by insertable dust filters and exhausting to Stacks S-2B and S-2C.

(D) Two (2) enclosed coal bunkers with a total loading capacity of 1800 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-3A and S-3B.

(2) Lime and soda ash handling system, to be permitted in 2010:

(A) Transfer of lime from truck or railcar by a closed pneumatic conveyor to two (2) lime storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4A and S-4B.

(B) Transfer of soda ash from truck or railcar by a closed pneumatic conveyor to two (2) soda ash storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4C and S-4D.

The following construction conditions are applicable to the proposed project:

1. Effective Date of the Permit
   Pursuant to IC 13-15-5-3, this approval becomes effective upon its issuance.

2. All requirements and conditions of this construction approval shall remain in effect unless modified in a manner consistent with procedures established pursuant to 326 IAC 2.

All other conditions of the permit shall remain unchanged and in effect. For your convenience, the entire Part 70 Operating Permit as modified will be provided at issuance.

This decision is subject to the Indiana Administrative Orders and Procedures Act – IC 4-21.5-3-5. If you have any questions on this matter, please contact Josiah Balogun, OAQ, 100 North Senate Avenue, MC 61-53, Room 1003, Indianapolis, Indiana, 46204-2251, or call at (800) 451-6027, and ask for Josiah Balogun or extension (4-52-57), or dial (317) 234-5257.

Sincerely,

Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Attachments:
Updated Permit
Technical Support Document
PTE Calculations

JB

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

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PSD/Part 70 Significant Source Modification
OFFICE OF AIR QUALITY

Duke Energy Indiana - Edwardsport Generating Station
15424 East State Road 358
Edwardsport, Indiana 47258

(herein known as the Permittee) is hereby authorized to construct and 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. This permit also addresses certain new source review requirements for existing equipment and is intended to fulfill the new source review procedures pursuant to 326 IAC 2-2 and 326 IAC 2-7-10.5, applicable to those conditions.

PSD/Significant Source Modification No.: T083-28683-00003	
Issued by: Matthew Stuckey, Branch Chief Permits Branch Office of Air Quality	Issuance Date: March 1, 2010

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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 electric utility generating station.

Source Address:	15424 East State Road 358, Edwardsport, Indiana 47258
Mailing Address:	c/o Mack Sims, 1000 East Main Street, Plainfield, IN 46168
General Source Phone Number:	317-838-6937
SIC Code:	4911
County Location:	Knox
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Major Source (Existing Plant), Section 112 of the Clean Air Act Minor Source (IGCC Plant), 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) **Emission Units at the Existing Coal-Fired Power Plant to be Retired prior to operation of the IGCC Plant:**

(a) One (1) No. 2 fuel oil-fired boiler, identified as Boiler No. 6-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr) and exhausting to stack 6-1.

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 7-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 7-1. Stack 7-1 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

(c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 7-2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 7-2. Stack 7-2 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

(d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 8-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 8-1. Stack 8-1 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

(e) A coal transfer system, with a nominal throughput of 300 tons of coal per hour, construction commenced prior to 1974, consisting of the following equipment:

(1) One (1) unloading station for trucks, with a drop point to a coal storage pile identified as F-1, with the drop point, identified as DP-1, controlled by a partial enclosure, and exhausting to the ambient air.

(2) One (1) storage pile area, having an estimated storage capacity of 70,000 tons, with fugitive emissions controlled by watering as needed.

(3) One (1) enclosed hopper, with a drop point identified as DP-3 to a conveyor identified as Conveyor C, with each drop point enclosed and exhausting to the ambient air.

(4) An enclosed conveyor system, with six (6) drop points identified as DP-3, DP-4, DP-5, DP-6, DP-7, and DP-8, with each drop point enclosed.

(5) Three (3) enclosed coal bunkers, each with a normal nominal capacity of 15,000 tons of coal. Bunkers are loaded via a conveyor tripper system with a total capacity of 300 tons per hour to the Boilers 7-1, 7-2 and 8-1 bunkers. Particulate matter generated from loading bunkers is controlled by enclosure and exhausts to the ambient air.

(B) **Integrated Gasification Combined Cycle (IGCC) Electric Generating Plant:**

(a) One gasification block with acid gas removal/sulfur recovery, particulate removal and mercury removal consisting of the following:

(1) Two (2) refractory-lined, oxygen-blown, entrained flow gasifiers designated as GASIF1 and GASIF2, permitted in 2008, exhausting through Vents S-5a1 and S-5a2 during startup only.

(2) Two (2) natural gas fired gasification preheaters designated as GPREHEAT1 and GPREHEAT2, permitted in 2008, with a maximum heat input capacity of 19.1 MMBtu/hr each (high heating value basis), exhausting to Vents S-5a1 and S-5a2 during startup only.

(3) One (1) natural gas fired thermal oxidizer designated as THRMOX, permitted in 2008, with a maximum heat input for the pilot of 3.85 MMBtu/hr, exhausting to Stack S-4. The thermal oxidizer will combust waste gas streams from the Sulfur Recovery Unit (SRU) sulfur pit vents and intermittent gas streams for the SRU during startup, shutdown and trip events.

(4) One natural gas fired elevated open flare designated as FLR, permitted in 2008, with a maximum heat input for the pilot of 1.23 MMBtu/hr, exhausting to Stack S-3. An additional heat input of 1.44 MMBtu/hr (natural gas) will be provided to the flare as sweep enrichment gas/flare purge gas. The flare will combust syngas streams from various operations associated with the gasification process during startup, shutdown and trip events.

(b) One power block consisting of the following:

(1) Two (2) combined cycle combustion turbine trains each consisting of a combustion turbine and a heat recovery steam generator, designated as CTHRSG1 and CTHRSG2, permitted in 2008, using diffusion combustors firing either syngas, natural gas, or combined syngas and natural gas, and exhausting to Stacks S-2a and S-2b. The turbine trains use nitrogen diluent injection (to control NO_X) when firing syngas, steam injection when firing natural gas, and nitrogen diluent injection and steam injection when co-firing syngas and natural gas.

Nominal Heat Input Capacity (HHV) for each Combustion Turbine Train	
Fuel	**MMBtu/hr**
Syngas Only	2106
Natural Gas Only	2109
Combined Syngas and Natural Gas	2129

Stacks S-2a and S-2b have continuous emissions monitors (CEMs) for carbon monoxide (CO), nitrogen oxides (NO_X) and sulfur dioxide (SO_2). Mercury (Hg) will be monitored per requirements of 40 CFR Part 60, Subpart Da.

(2) One (1) reheat, condensing steam turbine, permitted in 2008.

(3) One (1) twenty-two (22) cell induced draft cooling tower designated as CT1 – CT22, permitted in 2008, exhausting to Stack S-9. The cooling tower will use a high-efficiency drift eliminator to control particulate emissions.

(4) One (1) natural gas fired auxiliary boiler designated as AUXBLR, permitted in 2008, with a maximum heat input capacity of 300 MMBtu/hr (high heating value basis) and exhausting to Stack S-6.

(5) Two (2) natural gas fired turbine gas conditioning preheaters designated as TPREHEAT1 and TPREHEAT2, permitted in 2008, with a maximum heat input capacity of 5 MMBtu/hr (per unit on a high heating value basis) and exhausting to Stacks S-5b1 and S-5b2 respectively.

(6) One (1) diesel-fired emergency generator designated as EMDSL, permitted in 2008, with a maximum rating of 2200 brake-horsepower (Bhp), exhausting to Stack S-7.

(7) One (1) diesel-fired emergency fire pump designated as FIRPMP, permitted in 2008, with a maximum rating of 420 brake-horsepower (Bhp), exhausting to Stack S-8.

(c) Material handling operations consisting of:

(1) Coal receiving and handling system, to be permitted in 2010, except the truck or railcar receiving and unloading station permitted in 2008, using enclosed conveyors consisting of the following equipment:

(A) 1200 ton per hour enclosed coal conveyor with particulate emissions from drop point to active coal pile stacking tube controlled by an insertable dust filter, exhausting to Stack S-1D.

(B) One (1) 1200 ton per hour truck or railcar receiving and unloading station with enclosed drop points and particulate emissions controlled by a baghouse and exhausting to Stack S-1B.

(C) One (1) 1,800 ton per hour reclaim tunnel, using two (2) 900 ton per hour conveyors with enclosed drop points and particulate matter controlled by a baghouse and exhausting to Stack S-2A.

(D) Two (2) 900 ton per hour enclosed coal conveyors with particulate matter from enclosed drop points controlled by insertable dust filters and exhausting to Stacks S-2B and S-2C.

(E) Two (2) enclosed coal bunkers with a total loading capacity of 1800 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S- 3A and S-3B.

(2) Lime and soda ash handling system, to be permitted in 2010:

(A) Transfer of lime from truck or railcar by a closed pneumatic conveyor to two (2) lime storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4A and S-4B.

(B) Transfer of soda ash from truck or railcar by a closed pneumatic conveyor to two (2) soda ash storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4C and S- 4D.

(d) Fugitive dust emissions consisting of:

(1) Coal storage piles including one (1) inactive coal pile identified as CP_IN, permitted in 2008, and one (1) active coal pile identified as CP_AC, permitted in 2008.

(2) Slag storage pile and slag handling, permitted in 2008.

(3) Paved roads, permitted in 2008.

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):

Operations for Original Coal-Fired Power Plant, To Be Retired:

(a) Cleaners and solvents characterized as follows: [326 IAC 8-3]

(1) Having a vapor pressure equal to or less than 2 kPa; 15 mm Hg; or 0.3 psi measured at 38 degrees C (100^{O}F) or;

(2) 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.

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

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 permit, T 083-7243-00003, is issued for a fixed term of five (5) years from the date of its issuance , as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of the Part 70 permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

(b) If IDEM, OAQ, upon receiving a timely and complete renewal permit application, fails to issue or deny the permit renewal prior to the expiration date of this Part 70 permit, as modified, this permit shall not expire and all terms and conditions shall continue in effect, including any permit shield provided in 326 IAC 2-7-15, until the renewal permit has been issued or denied.

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

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

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

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

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

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

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

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

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

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

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

(a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The submittal by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34). Upon request, the Permittee shall also furnish to IDEM, OAQ copies of records required to be kept by this permit.

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

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

(a) Where specifically designated by this permit or required by an applicable requirement, any application form, report, or compliance certification submitted shall contain certification by the "responsible official" of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) One (1) certification shall be included, using the attached Certification Form, with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.

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

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

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

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

and

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

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

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

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

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

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

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

The submittal by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance Section), or
Telephone Number: 317-233-0178 (ask for Compliance Section)
Facsimile Number: 317-233-6865

Southwest Regional Office phone: (812) 380-2305; fax: (812) 380-2304.

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

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

and

Southwest Regional Office
1120 N. Vincennes Avenue
P.O. Box 128
Petersburg, Indiana 47567-0128

within two (2) working days of the time when emission limitations were exceeded due to the emergency.

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

(A) A description of the emergency;

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

(C) Corrective actions taken.

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

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

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

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

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

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

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

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

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

(a) Pursuant to 326 IAC 2-7-15, the Permittee has been granted a permit shield in accordance with this Condition. 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 T 083-7243-00003 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 combined permit, all previous registrations and permits are superseded by this combined new source review and 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 Part 70 Operating Permit, T 083-7243-00003, unless a timely and complete renewal application is submitted at least nine (9) months prior to the date of expiration of the source's existing permit, consistent with 326 IAC 2-7-3 and 326 IAC 2-7-4(a).

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

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

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

using the attached Quarterly Deviation and Compliance Monitoring Report, or its equivalent. A deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report.

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

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

B.16 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)] [326 IAC 2-7-8(a)] [326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ determines any of the following:

(1) That this permit contains a material mistake.

(2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.

(3) That this permit must be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-7-9(a)(3)]

(c) Proceedings by IDEM, OAQ to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-7-9(b)]

(d) The reopening and revision of this permit, under 326 IAC 2-7-9(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ may provide a shorter time period in the case of an emergency. [326 IAC 2-7-9(c)]

B.17 Permit Renewal [326 IAC 2-7-3] [326 IAC 2-7-4] [326 IAC 2-7-8(e)]

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

Request for renewal shall be submitted to:

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

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

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

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

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

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

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

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

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

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

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

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

B.19 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)] [326 IAC 2-7-12(b)(2)]

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

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

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

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

(1) The changes are not modifications under any provision of Title I of the Clean Air Act;

(2) Any preconstruction approval required by 326 IAC 2-7-10.5 has been obtained;

(3) The changes do not result in emissions that exceed the limitations provided in this permit (whether expressed herein as a rate of emissions or in terms of total emissions);

(4) The Permittee notifies the:

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

and

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

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

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

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

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(36)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

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

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

(3) Any change in emissions; and

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

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

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

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

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

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

B.21 Source Modification [326 IAC 1-2-42] [326 IAC 2-7-10.5] [326 IAC 2-2-2] [326 IAC 2-3-2]

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

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

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

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

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

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

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

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

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

B.22 Inspection and Entry [326 IAC 2-7-6] [IC 13-14-2-2] [IC 13-30-3-1] [IC 13-17-3-2]

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

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

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

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

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

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

B.23 Transfer of Ownership or Operational Control [326 IAC 2-7-11]

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

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

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

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

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

B.24 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)] [326 IAC 2-1.1-7]

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

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

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

B.25 Credible Evidence [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [62 FR 8314] [326 IAC 1-1-6]

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

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

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

C.2 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

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

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

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

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

The Permittee shall not operate an incinerator or incinerate any waste or refuse except as provided in 326 IAC 4-2 and 326 IAC 9-1-2.

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

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

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

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

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

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

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

C.8 Performance Testing [326 IAC 3-6]

(a) Compliance testing on new emissions units shall be conducted within 60 days after achieving maximum production rate, but no later than 180 days after initial start-up, if specified in Section D of this approval. All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this permit, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.

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

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

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

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

Compliance Requirements [326 IAC 2-1.1-11]

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

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

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

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

Unless otherwise specified in this permit, all monitoring and record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance. If required by Section D, the Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. If due to circumstances beyond its control, that equipment cannot be installed and operated within ninety (90) days, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

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

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

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

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

C.11 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment. For a boiler, the COMS shall be in operation at all times that the induced draft fan is in operation.

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

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

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

(1) Visible emission readings shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, for a minimum of five (5) consecutive six (6) minute averaging periods beginning not more than twenty-four (24) hours after the start of the malfunction or down time.

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

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

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

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous opacity monitoring system pursuant to 326 IAC 3-5, (and 40 CFR 60 and/or 40 CFR 63).

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

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

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

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

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

C.13 Monitoring Methods [326 IAC 3] [40 CFR 60] [40 CFR 63]

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

C.14 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 pressure gauge or other 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.15 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

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

(a) The Permittee prepared and submitted written emergency reduction plans (ERPs) consistent with safe operating procedures on February 12, 1980.

(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.16 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.17 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) Upon detecting an excursion or exceedance, the Permittee shall restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(b) The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Corrective actions may include, but are not limited to, the following:

(1) initial inspection and evaluation;

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

(3) any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

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

(1) monitoring results;

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

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

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

(e) The Permittee shall maintain the following records:

(1) monitoring data;

(2) monitor performance data, if applicable; and

(3) corrective actions taken.

C.18 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall take appropriate response actions. The Permittee shall submit a description of these response actions to IDEM, OAQ, within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize excess emissions from the affected facility while the response actions are being implemented.

(b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred twenty (120) days is not practicable, IDEM, OAQ may extend the retesting deadline.

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

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

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

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

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

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

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

The statement must be submitted to:

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

The emission statement does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

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

C.20 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Unless otherwise specified in this permit, all record keeping requirements not already legally required shall be implemented when operation begins.

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

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

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

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

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

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

(e) The first report shall cover the period commencing on the date of issuance of this permit and ending on the last day of the reporting period. Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.

(f) If the Permittee is required to comply with the recordkeeping provisions of (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 Electric Utility Steam Generating Unit, then for that project the Permittee shall:

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

(2) Submit a report to IDEM, OAQ within sixty (60) days after the end of each year during which records are generated in accordance with (d)(1) and (2) in Section C - General Record Keeping Requirements. The report shall contain all information and data describing the annual emissions for the emissions units during the calendar year that preceded the submission of report.

Reports required in this part shall be submitted to:

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

(g) 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 other than an Electric Utility Steam Generating Unit, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:

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

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

(h) The report for a project at an existing emissions unit other than Electric Utility Steam Generating Unit shall be submitted within sixty (60) days after the end of the year and contain the following:

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

(2) The annual emissions calculated in accordance with (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 deems fit to include in this report,

Reports required in this part shall be submitted to:

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

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

Stratospheric Ozone Protection

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

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

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

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

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

(d) Pursuant to 40 CFR 82, Subpart E (The Labeling of Products Using Ozone-Depleting Substances), all containers in which a Class I or Class II substance is stored or transported and all products containing a Class I substance shall be labeled as required under 40 CFR Part 82.

Ambient Monitoring Requirements [326 IAC 7-3]

C.23 Ambient Monitoring [326 IAC 7-3]

(a) The Permittee shall operate continuous ambient sulfur dioxide air quality monitors and a meteorological data acquisition system according to a monitoring plan submitted to the commissioner for approval. The monitoring plan shall include requirements listed in 326 IAC 7-3-2(a)(1), 326 IAC 7-3-2(a)(2) and 326 IAC 7-3-2(a)(3).

(b) The Permittee and other operators subject to the requirements of this rule, located in the same county, may submit a joint monitoring plan to satisfy the requirements of this rule. [326 IAC 7-3-2(c)]

(c) The Permittee may petition the commissioner for an administrative waiver of all or some of the requirements of 326 IAC 7-3 if such owner or operator can demonstrate that ambient monitoring is unnecessary to determine continued maintenance of the sulfur dioxide ambient air quality standards in the vicinity of the source. [326 IAC 7-3-2(d)]

(d) If approved by the Commissioner, the Permittee may discontinue ambient sulfur dioxide air quality monitoring and meteorological data acquisition system if the actual sulfur dioxide emissions from the entire source are less than or equal to ten thousand (10,000) tons per year.

Retirement of Existing Operations

C.24 Retirement of Existing Operations [326 IAC 2-2]

Pursuant to 326 IAC 2-2, the Permittee shall permanently discontinue or terminate operation of all emission units at the existing coal-fired plant, including the following units, prior to initial startup of the new emission units of the IGCC plant:

(a) One (1) No. 2 fuel oil-fired boiler, identified as Boiler No. 6-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr) and exhausting to stack 6-1.

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 7-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 7-1. Stack 7-1 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

(c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 7-2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 7-2. Stack 7-2 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

(d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 8-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 8-1. Stack 8-1 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

(e) A coal transfer system, with a nominal throughput of 300 tons of coal per hour, construction commenced prior to 1974, consisting of the following equipment:

(1) One (1) unloading station for trucks, with a drop point to a coal storage pile identified as F-1, with the drop point, identified as DP-1, controlled by a partial enclosure, and exhausting to the ambient air.

(2) One (1) storage pile area, having an estimated storage capacity of 70,000 tons, with fugitive emissions controlled by watering as needed.

(3) One (1) enclosed hopper, with a drop point identified as DP-3 to a conveyor identified as Conveyor C, with each drop point enclosed and exhausting to the ambient air.

(4) An enclosed conveyor system, with 6 drop points identified as DP-3, DP-4, DP-5, DP-6, DP-7, and DP-8, with each drop point enclosed.

(5) Three (3) enclosed coal bunkers, each with a normal nominal capacity of 15,000 tons of coal. Bunkers are loaded via a conveyor tripper system with a total capacity of 300 tons per hour to the Boilers 7-1, 7-2 and 8-1 bunkers. Particulate matter generated from loading bunkers is controlled by enclosure and exhausts to the ambient air.

(f) All insignificant Activities, as defined in 326 IAC 2-7-1(21), associated with the units to be retired, will also be permanently discontinued when the emission units described above are retired.

SECTION D.1 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Units at the Existing Coal-Fired Power Plant to be Retired prior to operation of the IGCC Plant:
One (1) No. 2 Fuel oil-fired boiler, identified as Boiler No. 6-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr) and exhausting to stack 6-1.

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

D.1.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(c)), the PM emissions from the Boiler No. 6-1 stack shall not exceed 0.223 pound per million Btu heat input (lb/MMBtu). This limitation was calculated using the following equation:

$$Pt = \frac{(C)\ (a)\ (h)}{76.5\ (Q^{0.75})\ (N^{0.25})}$$

Where C = 50 μ/m^3
Q = 2040 MMBtu/hr (capacity of all boilers)
N = 4 (number of stacks)
a = 0.8
h = 183 Feet (average stack height)

D.1.2 Sulfur Dioxide (SO_2) [326 IAC 7-1.1]

Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), the SO_2 emissions from Boiler No. 6-1 shall not exceed 0.5 pound per million Btu (lbs/MMBtu).

D.1.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for this facility and its emission control devices.

Compliance Determination Requirements

D.1.4 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

Compliance with the PM limitation in Condition D.1.1 shall be determined by a performance stack test conducted utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with Section C - Performance Testing.

D.1.5 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3] [326 IAC 7-2] [326 IAC 7-1.1]

Compliance with Condition D.1.2 shall be determined using one of the following options:

(a) Pursuant to 326 IAC 3-7-4, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed five-tenths (0.5) pound per million Btu heat input by:

(1) Providing vendor analysis of fuel delivered, if accompanied by a vendor certification, or;

(2) Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR 60, Appendix A, Method 19.

(A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and

(B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling.

(b) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the boiler using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.

(c) Upon written notification to IDEM by the Permittee, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

A determination of noncompliance pursuant to any of the methods specified in (a) or (b) above shall not be refuted by evidence of compliance pursuant to the other method.

D.1.6 Nitrogen Oxides Monitoring Requirement [326 IAC 10-4-4(b)(1)] [326 IAC 10-4-12(b) and (c)] [40 CFR 75]

The Permittee shall record, report, and quality assure the data from the monitoring systems for the NO_X budget units in accordance with 326 IAC 10-4-12 and 40 CFR 75.

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

D.1.7 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission (VE) notations of the boiler stack exhaust shall be performed once per day during normal daylight operations while combusting fuel oil. A trained employee shall record whether emissions are normal or abnormal.

(b) If abnormal emissions are observed at any boiler exhaust, 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.

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

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

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

D.1.8 Record Keeping Requirements

(a) To document compliance with Conditions D.1.2, the Permittee shall maintain records in accordance with (1) through (5) below. Records maintained for (1) through (5) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 limits as required in Conditions D.1.2.

(1) All fuel sampling and analysis data, pursuant to 326 IAC 7-2.

(2) Actual fuel usage since last compliance determination period.

If the fuel supplier certification is used to demonstrate compliance, when burning alternate fuels and not determining compliance pursuant to 326 IAC 3-7-4, the following, as a minimum, shall be maintained:

(3) Fuel supplier certifications;

(4) The name of the fuel supplier; and

(5) A statement from the fuel supplier that certifies the sulfur content of the fuel oil.

The Permittee shall retain records of all recording/monitoring data and support information for a period of five (5) years, or longer if specified elsewhere in this permit, from the date of the monitoring sample, measurement, or report.

(b) To document compliance with Condition D.1.7, the Permittee shall maintain records of visible emission notations of the boiler stack exhaust.

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

SECTION D.2 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Units at the Existing Coal-Fired Power Plant to be Retired prior to operation of the IGCC Plant:
One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 7-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 7-1. Stack 7-1 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

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

D.2.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(c)), the PM emissions from the Boiler No. 7-1 stack shall not exceed 0.223 pound per million Btu heat input (lb/MMBtu). This limitation was calculated using the following equation:

$$Pt = \frac{(C)\ (a)\ (h)}{76.5\ (Q^{0.75})\ (N^{0.25})}$$

Where C = 50 □/m^3
Q = 2040 MMBtu/hr (capacity of all boilers)
N = 4 (number of stacks)
a = 0.8
h = 183 Feet (average stack height)

D.2.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

Pursuant to 326 IAC 5-1-3(e) (Temporary Alternative Opacity Limitations), the following applies:

(a) When building a new fire in a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed two (2) hours (twenty (20) six (6)-minute averaging periods) or until the flue gas temperature reaches two hundred fifty (250) degrees Fahrenheit entering the electrostatic precipitator, whichever occurs first.

(b) When shutting down a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed 30 minutes (five (5) six (6)-minute averaging periods).

(c) Operation of the electrostatic precipitator is not required during these times.

(d) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed the applicable limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of the applicable limit shall not continue for more than one (1) six (6)-minute averaging period in any sixty (60) minute period. The averaging periods shall not be permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period. [326 IAC 5-1-3(b)]

D.2.3 Sulfur Dioxide (SO_2) [326 IAC 7-1.1]

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

D.2.4 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for this facility and its emission control devices.

Compliance Determination Requirements

D.2.5 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

By December 31 of the second calendar year following the most recent stack test, compliance with the PM limitation in Condition D.2.1 shall be determined by a performance stack test conducted utilizing methods as approved by the Commissioner. This testing shall be repeated by December 31 of every second calendar year following this valid compliance demonstration. Testing shall be conducted in accordance with Section C- Performance Testing.

D.2.6 Particulate Control [326 IAC 2-7-6(6)]

In order to comply with Condition D.2.1, the electrostatic precipitator shall be operated at all times that the Boiler No. 7-1 is in operation and combusting fuel.

D.2.7 Continuous Emissions Monitoring [326 IAC 3-5]

Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), continuous emission monitoring systems shall be calibrated, maintained, and operated for measuring opacity, which meet all applicable performance specifications of 326 IAC 3-5-2.

D.2.8 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3] [326 IAC 7-2] [326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-2, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed six (6.0) pounds per MMBtu. Compliance shall be determined utilizing the following options:

(a) Providing vendor analysis of coal delivered, if accompanied by a certification from the fuel supplier as described under 40 CFR 60.48c(f)(3). The certification shall include:

(1) The name of the coal supplier; and

(2) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the coal was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected); and

(3) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(4) The methods used to determine the properties of the coal; **and**

(b) Sampling and analyzing the coal using one of the following procedures:

(1) Minimum Coal Sampling Requirements and Analysis Methods:

(A) The coal sample acquisition point shall be at a location where representative samples of the total coal flow to be combusted by the facility or facilities may be obtained. A single as-bunkered or as-burned sampling station may be used to represent the coal to be combusted by multiple facilities using the same stockpile feed system;

(B) Coal shall be sampled at least one (1) time per day;

(C) Minimum sample size shall be five hundred (500) grams;

(D) Samples shall be composited and analyzed at the end of each calendar quarter;

(E) Preparation of the coal sample, heat content analysis, and sulfur content analysis shall be determined pursuant to 326 IAC 3-7-2(c), (d), (e); or

(2) Sample and analyze the coal pursuant to 326 IAC 3-7-3; or

(c) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the boiler, using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6, which is conducted with such frequency as to generate the amount of information required by (a) or (b) above. [326 IAC 7-2-1(b)]

(d) Upon written notification to IDEM by the Permittee, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

A determination of noncompliance pursuant to any of the methods specified in (a), (b), or (c) above shall not be refuted by evidence of compliance pursuant to the other method.

D.2.9 Nitrogen Oxides Monitoring Requirement [326 IAC 10-4-4(b)(1)] [326 IAC 10-4-12(b) and (c)] [40 CFR 75]

The Permittee shall record, report, and quality assure the data from the monitoring systems for the NO_X budget units in accordance with 326 IAC 10-4-12 and 40 CFR 75.

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

D.2.10 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

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

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

D.2.11 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Appropriate response steps shall be taken in accordance with Section C - Response to Excursion or Exceedances whenever the opacity exceeds twenty percent (20%) for three (3) consecutive six (6) minute averaging periods. In the event of opacity exceeding twenty percent (20%), response steps will be taken such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty percent (20%). Examples of expected response steps include, but are not limited to, boiler loads being reduced and ESP T-R sets being returned to service.

(b) Opacity readings in excess of twenty percent (20%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursion or Exceedances, shall be considered a deviation from this permit.

(c) The Permittee may request that the IDEM, OAQ approve a different opacity trigger level than the one specified in (a) and (b) of this condition, provided the Permittee can demonstrate, through stack testing or other appropriate means, that a different opacity trigger level is appropriate for monitoring compliance with the applicable particulate matter mass emission limits.

D.2.12 SO_2 Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

Whenever the automatic coal sampling system is malfunctioning or down for repairs or adjustments for twenty-four (24) hours or more, the following shall be used to provide information related to SO_2 emissions:

(a) Fuel sampling shall be conducted as specified in 326 IAC 3-7-2(a) or (b). Fuel sample preparation and analysis shall be conducted as specified in 326 IAC 3-7-2(c), 326 IAC 3-7-2(d), and 326 IAC 3-7-2(e). Pursuant to 326 IAC 3-7-3, manual or other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring.

(b) If during the life of this permit the Permittee notifies the IDEM that, pursuant to 326 IAC 7-2-1(g), continuous emission monitoring data will be used instead of fuel sampling and analysis, then whenever the SO_2 continuous emission monitoring system is malfunctioning or down for repairs or adjustments, the following shall be used to provide information related to SO_2 emissions:

(1) If the CEM system is down for less than twenty-four (24) hours, the Permittee shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

(2) If the CEM system is down for twenty-four (24) hours or more, fuel sampling shall be conducted as specified in part (a) of this condition, above.

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

D.2.13 Record Keeping Requirements

(a) To document compliance with Section C - Opacity and Conditions D.2.1, D.2.2, D.2.7, D.2.10, and D.2.11, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.2.1 and D.2.2.

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

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

(3) The results of all visible emission (VE) notations and Method 9 visible emission readings taken during any periods of COM downtime.

(4) All ESP parametric monitoring readings.

(b) To document compliance with Condition D.2.3, the Permittee shall maintain records in accordance with (1) and (2) below. Records maintained for (1) and (2) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 limits as required in Condition D.2.3. The Permittee shall maintain records in accordance with (2) below during SO_2 CEM system downtime if a backup CEM is not used.

(1) Whenever using CEMS data to demonstrate compliance with Condition D.2.3, the Permittee shall maintain all SO_2 continuous emissions monitoring data, pursuant to 326 IAC 7-2-1(g), with calendar dates and beginning and ending times of any CEMS downtime.

(2) Whenever the Permittee is not using CEMS data to demonstrate compliance with Condition D.2.3, the Permittee shall maintain records in accordance with (A) through (E) below. Records maintained for (A) through (E) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 emission limit established in Condition D.2.3.

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

(B) Actual coal usage since last compliance determination period; and;

(C) Sulfur content, heat content, and ash content; and;

(D) Sulfur dioxide emission rates; and;

(E) Vendor analysis of coal and coal supplier certification.

(c) Pursuant to 326 IAC 3-7-5(a), the Permittee shall develop a standard operating procedure (SOP) to be followed for sampling, handling, analysis, quality control, quality assurance, and data reporting of the information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4. In addition, any revision to the SOP shall be submitted to IDEM, OAQ.

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

D.2.14 Reporting Requirements

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

(b) A quarterly report of the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per million Btus, and records of the daily average coal sulfur content, coal heat content, weighing factor, and daily average sulfur dioxide emission rate in pounds per million Btus shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported. [326 IAC 7-2-1(c)(1)]

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

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

SECTION D.3 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Units at the Existing Coal-Fired Power Plant to be Retired prior to operation of the IGCC Plant:
One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 7-2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 7-2. Stack 7-2 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

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

D.3.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(c)), the PM emissions from the Boiler No. 7-2 stack shall not exceed 0.223 pound per million Btu heat input (lb/MMBtu). This limitation was calculated using the following equation:

$$Pt = \frac{(C)\,(a)\,(h)}{76.5\ (Q^{0.75})\ (N^{0.25})}$$

Where $C = 50\ \mu/m^3$
Q = 2040 MMBtu/hr (capacity of all boilers)
N = 4 (number of stacks)
a = 0.8
h = 183 Feet (average stack height)

D.3.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

Pursuant to 326 IAC 5-1-3(e) (Temporary Alternative Opacity Limitations), the following applies:

(a) When building a new fire in a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed two (2) hours (twenty (20) six (6)-minute averaging periods) or until the flue gas temperature reaches two hundred fifty (250) degrees Fahrenheit entering the electrostatic precipitator, whichever occurs first.

(b) When shutting down a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed 30 minutes (five (5) six (6)-minute averaging periods).

(c) Operation of the electrostatic precipitator is not required during these times.

(d) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed the applicable limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of the applicable limit shall not continue for more than one (1) six (6)-minute averaging period in any sixty (60) minute period. The averaging periods shall not be permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period. [326 IAC 5-1-3(b)]

D.3.3 Sulfur Dioxide (SO_2) [326 IAC 7-1.1]

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

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

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for this facility and its emission control devices.

Compliance Determination Requirements

D.3.5 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

By December 31 of the second calendar year following the most recent stack test, compliance with the PM limitation in Condition D.3.1 shall be determined by a performance stack test conducted utilizing methods as approved by the Commissioner. This testing shall be repeated by December 31 of every second calendar year following this valid compliance demonstration. Testing shall be conducted in accordance with Section C- Performance Testing.

D.3.6 Particulate Control [326 IAC 2-7-6(6)]

In order to comply with Condition D.3.1, the electrostatic precipitator shall be operated at all times that the Boiler No. 7-2 is in operation and combusting fuel.

D.3.7 Continuous Emissions Monitoring [326 IAC 3-5]

Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), continuous emission monitoring systems shall be calibrated, maintained, and operated for measuring opacity, which meet all applicable performance specifications of 326 IAC 3-5-2.

D.3.8 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3] [326 IAC 7-2] [326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-2, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed six (6.0) pounds per MMBtu. Compliance shall be determined utilizing the following options:

(a) Providing vendor analysis of coal delivered, if accompanied by a certification from the fuel supplier as described under 40 CFR 60.48c(f)(3). The certification shall include:

(1) The name of the coal supplier; and

(2) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the coal was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected); and

(3) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(4) The methods used to determine the properties of the coal; and

(b) Sampling and analyzing the coal using one of the following procedures:

(1) Minimum Coal Sampling Requirements and Analysis Methods:

(A) The coal sample acquisition point shall be at a location where representative samples of the total coal flow to be combusted by the facility or facilities may be obtained. A single as-bunkered or as-burned sampling station may be used to represent the coal to be combusted by multiple facilities using the same stockpile feed system;

(B) Coal shall be sampled at least one (1) time per day;

(C) Minimum sample size shall be five hundred (500) grams;

(D) Samples shall be composited and analyzed at the end of each calendar quarter;

(E) Preparation of the coal sample, heat content analysis, and sulfur content analysis shall be determined pursuant to 326 IAC 3-7-2(c), (d), (e); or

(2) Sample and analyze the coal pursuant to 326 IAC 3-7-3; or

(c) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the boiler, using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6, which is conducted with such frequency as to generate the amount of information required by (a) or (b) above. [326 IAC 7-2-1(b)]

(d) Upon written notification to IDEM by the Permittee, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

A determination of noncompliance pursuant to any of the methods specified in (a), (b), or (c) above shall not be refuted by evidence of compliance pursuant to the other method.

D.3.9 Nitrogen Oxides Monitoring Requirement [326 IAC 10-4-4(b)(1)] [326 IAC 10-4-12(b) and (c)] [40 CFR 75]

The Permittee shall record, report, and quality assure the data from the monitoring systems for the NO_X budget units in accordance with 326 IAC 10-4-12 and 40 CFR 75.

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

D.3.10 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

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

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

D.3.11 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Appropriate response steps shall be taken in accordance with Section C - Response to Excursion or Exceedances whenever the opacity exceeds twenty percent (20%) for three (3) consecutive six (6) minute averaging periods. In the event of opacity exceeding twenty percent (20%), response steps will be taken such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty percent (20%). Examples of expected response steps include, but are not limited to, boiler loads being reduced and ESP T-R sets being returned to service.

(b) Opacity readings in excess of twenty percent (20%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursion or Exceedances, shall be considered a deviation from this permit.

(c) The Permittee may request that the IDEM, OAQ approve a different opacity trigger level than the one specified in (a) and (b) of this condition, provided the Permittee can demonstrate, through stack testing or other appropriate means, that a different opacity trigger level is appropriate for monitoring compliance with the applicable particulate matter mass emission limits.

D.3.12 SO_2 Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

Whenever the automatic coal sampling system is malfunctioning or down for repairs or adjustments for twenty-four (24) hours or more, the following shall be used to provide information related to SO_2 emissions:

(a) Fuel sampling shall be conducted as specified in 326 IAC 3-7-2(a) or (b). Fuel sample preparation and analysis shall be conducted as specified in 326 IAC 3-7-2(c), 326 IAC 3-7-2(d), and 326 IAC 3-7-2(e). Pursuant to 326 IAC 3-7-3, manual or other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring.

(b) If during the life of this permit the Permittee notifies the IDEM that, pursuant to 326 IAC 7-2-1(g), continuous emission monitoring data will be used instead of fuel sampling and analysis, then whenever the SO_2 continuous emission monitoring system is malfunctioning or down for repairs or adjustments, the following shall be used to provide information related to SO_2 emissions:

(1) If the CEM system is down for less than twenty-four (24) hours, the Permittee shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

(2) If the CEM system is down for twenty-four (24) hours or more, fuel sampling shall be conducted as specified in part (a) of this condition, above.

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

D.3.13 Record Keeping Requirements

(a) To document compliance with Section C - Opacity and Conditions D.3.1, D.3.2, D.3.7, D.3.10, and D.3.11, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.3.1 and D.3.2.

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

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

(3) The results of all visible emission (VE) notations and Method 9 visible emission readings taken during any periods of COM downtime.

(4) All ESP parametric monitoring readings.

(b) To document compliance with Conditions D.3.3, the Permittee shall maintain records in accordance with (1) and (2) below. Records maintained for (1) and (2) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 limits as required in Condition D.3.3. The Permittee shall maintain records in accordance with (2) below during SO_2 CEM system downtime if a backup CEM is not used.

(1) Whenever using CEMS data to demonstrate compliance with Condition D.3.3, the Permittee shall maintain all SO_2 continuous emissions monitoring data, pursuant to 326 IAC 7-2-1(g), with calendar dates and beginning and ending times of any CEMS downtime.

(2) Whenever the Permittee is not using CEMS data to demonstrate compliance with Condition D.3.3, the Permittee shall maintain records in accordance with (A) through (E) below. Records maintained for (A) through (E) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 emission limit established in Condition D.3.3.

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

(B) Actual coal usage since last compliance determination period; and;

(C) Sulfur content, heat content, and ash content; and;

(D) Sulfur dioxide emission rates; and;

(E) Vendor analysis of coal and coal supplier certification.

(c) Pursuant to 326 IAC 3-7-5(a), the Permittee shall develop a standard operating procedure (SOP) to be followed for sampling, handling, analysis, quality control, quality assurance, and data reporting of the information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4. In addition, any revision to the SOP shall be submitted to IDEM, OAQ.

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

D.3.14 Reporting Requirements

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

(b) A quarterly report of the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per million Btus, and records of the daily average coal sulfur content, coal heat content, weighing factor, and daily average sulfur dioxide emission rate in pounds per million Btus shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported. [326 IAC 7-2-1(c)(1)]

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

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

SECTION D.4 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

<u>Emission Units at the Existing Coal-Fired Power Plant to be Retired prior to operation of the IGCC Plant:</u>
One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 8-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 8-1. Stack 8-1 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

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

D.4.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(c)), the PM emissions from the Boiler No. 8-1 stack shall not exceed 0.223 pound per million Btu heat input (lb/MMBtu). This limitation was calculated using the following equation:

$$Pt = \frac{(C)\ (a)\ (h)}{76.5\ (Q^{0.75})\ (N^{0.25})}$$

Where $C = 50\ \mu/m^3$
$Q =$ 2040 MMBtu/hr (capacity of all boilers)
$N =$ 4 (number of stacks)
$a =$ 0.8
$h =$ 183 Feet (average stack height)

D.4.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

Pursuant to 326 IAC 5-1-3(e) (Temporary Alternative Opacity Limitations), the following applies:

(a) When building a new fire in a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed two (2) hours (twenty (20) six (6)-minute averaging periods) or until the flue gas temperature reaches two hundred fifty (250) degrees Fahrenheit entering the electrostatic precipitator, whichever occurs first.

(b) When shutting down a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed 30 minutes (five (5) six (6)-minute averaging periods).

(c) Operation of the electrostatic precipitator is not required during these times.

(d) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed the applicable limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of the applicable limit shall not continue for more than one (1) six (6)-minute averaging period in any sixty (60) minute period. The averaging periods shall not be permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period. [326 IAC 5-1-3(b)]

D.4.3 Sulfur Dioxide (SO_2) [326 IAC 7-1.1]

Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), the SO_2 emissions from Boiler No. 8-1 shall not exceed 6.0 pounds per million Btu (lbs/MMBtu).

D.4.4 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for this facility and its emission control devices.

Compliance Determination Requirements

D.4.5 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

By December 31 of the second calendar year following the most recent stack test, compliance with the PM limitation in Condition D.4.1 shall be determined by a performance stack test conducted utilizing methods as approved by the Commissioner. This testing shall be repeated by December 31 of every second calendar year following this valid compliance demonstration. Testing shall be conducted in accordance with Section C - Performance Testing.

D.4.6 Particulate Control [326 IAC 2-7-6(6)]

In order to comply with Condition D.4.1, the electrostatic precipitator shall be operated at all times that the Boiler No. 8-1 is in operation and combusting fuel.

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

Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), continuous emission monitoring systems shall be calibrated, maintained, and operated for measuring opacity, which meet all applicable performance specifications of 326 IAC 3-5-2.

D.4.8 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3] [326 IAC 7-2] [326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-2, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed six (6.0) pounds per MMBtu**.** Compliance shall be determined utilizing the following options:

(a) Providing vendor analysis of coal delivered, if accompanied by a certification from the fuel supplier as described under 40 CFR 60.48c(f)(3). The certification shall include:

(1) The name of the coal supplier; and

(2) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the coal was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected); and

(3) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(4) The methods used to determine the properties of the coal; and

(b) Sampling and analyzing the coal using one of the following procedures:

(1) Minimum Coal Sampling Requirements and Analysis Methods:

(A) The coal sample acquisition point shall be at a location where representative samples of the total coal flow to be combusted by the facility or facilities may be obtained. A single as-bunkered or as-burned sampling station may be used to represent the coal to be combusted by multiple facilities using the same stockpile feed system;

(B) Coal shall be sampled at least one (1) time per day;

(C) Minimum sample size shall be five hundred (500) grams;

(D) Samples shall be composited and analyzed at the end of each calendar quarter;

(E) Preparation of the coal sample, heat content analysis, and sulfur content analysis shall be determined pursuant to 326 IAC 3-7-2(c), (d), (e); or

(2) Sample and analyze the coal pursuant to 326 IAC 3-7-3; or

(c) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the boiler, using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6, which is conducted with such frequency as to generate the amount of information required by (a) or (b) above. [326 IAC 7-2-1(b)]

(d) Upon written notification to IDEM by the Permittee, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

A determination of noncompliance pursuant to any of the methods specified in (a), (b), or (c) above shall not be refuted by evidence of compliance pursuant to the other method.

D.4.9 Nitrogen Oxides Monitoring Requirement [326 IAC 10-4-4(b)(1)] [326 IAC 10-4-12(b) and (c)] [40 CFR 75]

The Permittee shall record, report, and quality assure the data from the monitoring systems for the NO_X budget units in accordance with 326 IAC 10-4-12 and 40 CFR 75.

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

D.4.10 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

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

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

D.4.11 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Appropriate response steps shall be taken in accordance with Section C - Response to Excursion or Exceedances whenever the opacity exceeds twenty percent (20%) for three (3) consecutive six (6) minute averaging periods. In the event of opacity exceeding twenty percent (20%), response steps will be taken such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty percent (20%). Examples of expected response steps include, but are not limited to, boiler loads being reduced and ESP T-R sets being returned to service.

(b) Opacity readings in excess of twenty percent (20%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursion or Exceedances, shall be considered a deviation from this permit.

(c) The Permittee may request that the IDEM, OAQ approve a different opacity trigger level than the one specified in (a) and (b) of this condition, provided the Permittee can demonstrate, through stack testing or other appropriate means, that a different opacity trigger level is appropriate for monitoring compliance with the applicable particulate matter mass emission limits.

D.4.12 SO_2 Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

Whenever the automatic coal sampling system is malfunctioning or down for repairs or adjustments for twenty-four (24) hours or more, the following shall be used to provide information related to SO_2 emissions:

(a) Fuel sampling shall be conducted as specified in 326 IAC 3-7-2(a) or (b). Fuel sample preparation and analysis shall be conducted as specified in 326 IAC 3-7-2(c), 326 IAC 3-7-2(d), and 326 IAC 3-7-2(e). Pursuant to 326 IAC 3-7-3, manual or other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring.

(b) If during the life of this permit the Permittee notifies the IDEM that, pursuant to 326 IAC 7-2-1(g), continuous emission monitoring data will be used instead of fuel sampling and analysis, then whenever the SO_2 continuous emission monitoring system is malfunctioning or down for repairs or adjustments, the following shall be used to provide information related to SO_2 emissions:

(1) If the CEM system is down for less than twenty-four (24) hours, the Permittee shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

(2) If the CEM system is down for twenty-four (24) hours or more, fuel sampling shall be conducted as specified in part (a) of this condition, above.

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

D.4.13 Record Keeping Requirements

(a) To document compliance with Section C - Opacity and Conditions D.4.1, D.4.2, D.4.7, D.4.10, and D.4.11, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.4.1 and D.4.2.

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

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

(3) The results of all visible emission (VE) notations and Method 9 visible emission readings taken during any periods of COM downtime.

(4) All ESP parametric monitoring readings.

(b) To document compliance with Condition D.4.3, the Permittee shall maintain records in accordance with (1) and (2) below. Records maintained (1) and (2) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 limits as required in Condition D.4.3. The Permittee shall maintain records in accordance with (2) below during SO_2 CEM system downtime if a backup CEM is not used.

(1) Whenever using CEMS data to demonstrate compliance with Condition D.4.3, the Permittee shall maintain all SO_2 continuous emissions monitoring data, pursuant to 326 IAC 7-2-1(g), with calendar dates and beginning and ending times of any CEMS downtime.

(2) Whenever the Permittee is not using CEMS data to demonstrate compliance with Condition D.4.3, the Permittee shall maintain records in accordance with (A) through (E) below. Records maintained for (A) through (E) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 emission limit established in Condition D.4.3.

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

(B) Actual coal usage since last compliance determination period; and;

(C) Sulfur content, heat content, and ash content; and;

(D) Sulfur dioxide emission rates; and;

(E) Vendor analysis of coal and coal supplier certification.

(c) Pursuant to 326 IAC 3-7-5(a), the Permittee shall develop a standard operating procedure (SOP) to be followed for sampling, handling, analysis, quality control, quality assurance, and data reporting of the information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4. In addition, any revision to the SOP shall be submitted to IDEM, OAQ.

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

D.4.14 Reporting Requirements

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

(b) A quarterly report of the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per million Btus, and records of the daily average coal sulfur content, coal heat content, weighing factor, and daily average sulfur dioxide emission rate in pounds per million Btus shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported. [326 IAC 7-2-1(c)(1)]

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

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

SECTION D.5 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Units at the Existing Coal-Fired Power Plant to be Retired prior to operation of the IGCC Plant:
A coal transfer system, with a nominal throughput of 300 tons of coal per hour, construction commenced prior to 1974, consisting of the following equipment:

(1) One (1) unloading station for trucks, with a drop point to a coal storage pile identified as F-1, with the drop point, identified as DP-1, controlled by a partial enclosure, and exhausting to the ambient air.

(2) One (1) storage pile area, having an estimated storage capacity of 70,000 tons, with fugitive emissions controlled by watering as needed.

(3) One (1) enclosed hopper, with a drop point identified as DP-3 to a conveyor identified as Conveyor C, with each drop point enclosed and exhausting to the ambient air.

(4) An enclosed conveyor system, with 6 drop points identified as DP-3, DP-4, DP-5, DP-6, DP-7, and DP-8, with each drop point enclosed.

(5) Three (3) enclosed coal bunkers, each with a normal nominal capacity of 15,000 tons of coal. Bunkers are loaded via a conveyor tripper system with a total capacity of 300 tons per hour to the Boilers 7-1, 7-2 and 8-1 bunkers. Particulate matter generated from loading bunkers is controlled by enclosure and exhausts to the ambient air.

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

D.5.1 Particulate [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the coal storage and handling drop points, coal bunkers and scale exhausts, and associated dust collector vents shall not exceed 63 pounds per hour when operating at a process weight of 300 tons per hour (600,000 pounds per hour). This is determined by the following equation:

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

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

When the process weight rate exceeds two hundred (200) tons per hour, the maximum allowable emission may exceed 63 pounds per hour, provided the concentration of particulate matter in the discharge gases to the atmosphere is less than 0.10 pounds per one thousand (1,000) pounds of gases.

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

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for the watering system and the enclosures.

Compliance Determination Requirements

D.5.3 Particulate Control [326 IAC 2-7-6(6)]

In order to comply with Condition D.5.1, the Permittee shall maintain enclosures for particulate control at all times the associated coal processing or conveyors are in operation and the watering system for the coal storage pile shall be in operation and control emissions as needed when coal is being unloaded.

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

D.5.4 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)](a)

Visible emission notations of the coal storage and handling drop points, coal bunkers and scale exhausts, and associated dust collector vents shall be performed once per week during normal daylight operations. A trained employee shall record whether any emissions are observed.

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

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

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

If any abnormal emissions are observed from the coal storage and handling drop points, coal bunkers and scale exhausts, or associated dust collector vents, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursion or Exceedances. Visible emissions that do not violate 326 IAC 6-4 (Fugitive Dust Emissions), 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes) or an applicable opacity limit is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursion or Exceedances, shall be considered a deviation from this permit.

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

D.5.5 Record Keeping Requirements

(a) To document compliance with Section C - Opacity, Section C -Fugitive Dust Emissions, and Condition D.5.4, the Permittee shall maintain records of the visible emission notations of the coal storage and handling drop points, coal bunkers and scale exhausts, and associated dust collector vents and all response steps taken and the outcome for each.

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

SECTION D.6 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Units at the Existing Coal-Fired Power Plant to be Retired prior to operation of the IGCC Plant:
The following insignificant activities:

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

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

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

Pursuant to 326 IAC 8-3-2 (Cold Cleaner Operations), 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; and

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

D.6.2 Volatile Organic Compounds (VOC) [326 IAC 8-3-5]

(a) Pursuant to 326 IAC 8-3-5(a) (Cold Cleaner Degreaser Operation and Control) for a cold cleaner degreaser facility, the Permittee shall ensure that the following control equipment requirements are met:

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

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

(B) The solvent is agitated; or

(C) The solvent is heated.

(2) Equip the degreaser with a 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 ($38^{O}C$) (one hundred degrees Fahrenheit ($100^{O}F$)), 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 ($38^{O}C$) (one hundred degrees Fahrenheit ($100^{O}F$)), or if the solvent is heated to a temperature greater than forty-eight and nine-tenths degrees Celsius ($48.9^{O}C$) (one hundred twenty degrees Fahrenheit ($120^{O}F$)):

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

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

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

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

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

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

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

SECTION D.7 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Facility-wide Operations, which include the following:

(1) One gasification block with acid gas removal/sulfur recovery, particulate removal and mercury removal:

(2) One power block consisting of two (2) combined cycle combustion turbine trains each consisting of a combustion turbine and a heat recovery steam generator, one (1) reheat, condensing steam turbine; one (1) twenty-two (22) cell cooling; one (1) natural gas fired auxiliary boiler; two (2) natural gas fired turbine gas conditioning preheaters; one (1) diesel-fired emergency generator; one (1) diesel-fired emergency fire pump;

(3) Material handling operations consisting of coal receiving and handling system and lime handling system; and

(4) Fugitive dust emissions from coal storage piles, slag storage pile and slag handling, and paved roads

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

D.7.1 Facility-wide Operations - PSD Minor Limit [326 IAC 2-2]

In order to render the requirements of Prevention of Significant Deterioration (PSD) rules, 326 IAC 2-2, not applicable to emissions of NO_X and SO_2 from this source modification, IGCC plant-wide operations shall be limited as follows:

(a) Sulfur Dioxide (SO_2) emissions shall not exceed 358.5 tons per year (tpy) based on a 12-month rolling average (excluding startup and shutdowns);

(b) Nitrogen Oxide (NO_X) emissions shall not exceed 2121.5 tons per year (tpy) based on a 12-month rolling average (excluding startup and shutdowns); and

(c) Emissions from startup and shutdowns of the gasification and power blocks shall not exceed the following annual limits:

Annual Startup and Shutdown Emission Limits		
Equipment	**NO_X** (tpy)	**SO_2** (tpy)
Thermal Oxidizer	7.9	40.4
Flare	22.1	79.7
Gasification Preheaters	6.5	0.04
Aux Boiler	76.7	0.4
Combustion Turbines	153.2	1.9
Total	266.4	122.44

D.7.2 Gasification Block SO_2 Emission Limitation [326 IAC 2-2]

In order to render the requirements of Prevention of Significant Deterioration (PSD) rules, 326 IAC 2-2, not applicable to emissions of SO_2 from this source modification, the thermal oxidizer shall be limited as follows:

(a) Emissions of sulfur dioxide (SO_2) shall not exceed 19.86 lbs/hr during normal operation of the thermal oxidizer, THRMOX.

(b) Emissions of sulfur dioxide (SO_2) shall not exceed 150.9 lbs/hr during startup/shutdown operation of the thermal oxidizer, THRMOX.

Compliance Determination Requirements

D.7.3 Plant-wide SO_2 Operations (excluding startups/shutdowns)

In order to comply with Condition D.7.1(a), SO_2 emissions shall be based on a 12- month rolling average, determined on a monthly basis, using appropriate emission factors and, where available, monitoring data for each operation associated with the IGCC plant that has the potential to emit SO_2 under normal equipment operations.

D.7.4 Plant-wide NO_X Operations (excluding startup/shutdowns)

In order to comply with Condition D.7.1 (b), NO_X emissions shall be based on a 12- month rolling average, determined on a monthly basis, using appropriate emission factors and, where available, monitoring data for each operation associated with the IGCC plant that has the potential to emit NO_X.

D.7.5 Plant-wide NO_X and SO_2 Operations – Startups and Shutdowns

In order to comply with Condition D.7.1(c), SO_2 and NO_X emissions shall be based on a 12-month rolling average, determined on a monthly basis, using appropriate emission factors and number of specific startup and shutdown events per month.

(a) SO_2 and NO_X emissions from startup and shutdown events shall be based on the following calculation method:

(1) Appropriate startup and shutdown emission factor for each piece of emitting equipment in the tables below shall be multiplied by the number of startup and shutdown events of each type per month X 1/2000.

(A) Each startup and shutdown emission factor is the maximum pounds of that pollutant that shall be emitted for the specified event.

(i) The operational phases noted as phases 1 through 3 are typical of a cold startup at an IGCC plant. These emission factors represent cumulative emissions as the plant progresses through a cold startup.

(ii) The operational phase noted as phase 4 represents hot startup of an individual IGCC train.

(B) Each trip emission factor is the maximum pounds of that pollutant that shall be emitted for the startup trip event.

Startup and Shutdown Emission Factors Gasification Thermal Oxidizer – Syngas			
Equipment	**Operating Phase**	**NO_X** (lbs)	**SO_2** (lbs)
Startup Events			
Thermal Oxidizer – Syngas	Phase 1	6.27	0.032

Startup and Shutdown Emission Factors Gasification Thermal Oxidizer – Syngas			
Equipment	**Operating Phase**	**NO_X** (lbs)	**SO_2** (lbs)
Thermal Oxidizer – Syngas	Phase 2	184.13	293.8
Thermal Oxidizer – Syngas	Phase 3	191.9	789.8
Thermal Oxidizer – Syngas	Phase 4	4.29	327.2
Equipment Trip B to Thermal Oxidizer	N/A	3.5	815.2
Tail Gas Unit Trip to Thermal Oxidizer	N/A	2.1	897.4
Shutdown Events			
Thermal Oxidizer – Syngas	Partial Plant (≤ 5 hrs)	6.9	51.6
Thermal Oxidizer – Syngas	Entire Plant (> 5 hrs)	15.8	51.7

Startup and Shutdown Emission Factors Gasification Flare – Syngas			
Equipment	**Operating Phase**	**NO_X** (lbs)	**SO_2** (lbs)
Startup Event			
Flare – Syngas	Phase 1	3.9	0.03
Flare – Syngas	Phase 2	99.1	708.1
Flare – Syngas	Phase 3	182.4	1396.7
Flare – Syngas	Phase 4	81.25	688.5
SRU Trip to Flare	N/A	11.2	642.9
Equipment Trip A to Flare	N/A	11.3	394.6
CT Trip to Flare	N/A	769.9	72.1
Shutdown Event			
Flare – Syngas	Partial Plant (≤ 5 hrs)	158.6	499.0
Flare – Syngas	Entire Plant (> 5 hrs)	163.8	499.0

Startup and Shutdown Emission Factors Gasification Preheaters / Gasifiers – Syngas			
Equipment	**Operating Phase**[1]	**NO_X** (lbs)	**SO_2** (lbs)
Startup Event			
Preheaters / Gasifiers – Syngas	Phase 1	39.3	0.29
Preheaters / Gasifiers – Syngas	Phase 2	140.4	1.05
Preheaters / Gasifiers – Syngas	Phase 3	172.0	1.27
Shutdown Event			
Preheaters / Gasifiers – Syngas	Partial Plant (≤ 5 hrs)	N/A	N/A
Preheaters / Gasifiers – Syngas	Entire Plant (> 5 hrs)	N/A	N/A

[1] Gasification pre-heaters are only required to be operational while the gasifiers are being brought up to the required temperature. Gasifier pre-heaters are not required for a hot start-up of an individual gasification train.

Startup and Shutdown Emission Factors
Gasification Auxiliary Boiler – Natural Gas

Equipment	Operating Phase[1]	NO_X (lbs)	SO_2 (lbs)
Startup Event			
Aux. Boiler – Natural Gas	Phase 1	1317.6	7.1
Aux. Boiler – Natural Gas	Phase 2	2017.5	10.9
Aux. Boiler – Natural Gas	Phase 3	2017.5	10.9
Shutdown Event			
Aux. Boiler – Natural Gas	Partial Plant (≤ 5 hrs)	N/A	N/A
Aux. Boiler – Natural Gas	Entire Plant (> 5 hrs)	N/A	N/A

[1] The Auxiliary Boiler is only required to be in operation during the first 50 hours of a cold startup. The Gasification Auxiliary Boiler is not required for a hot start-up of an individual gasification train.

Startup and Shutdown Emission Factors
Gasification Combustion Turbines – Syngas

Equipment	Operating Phase	NO_X (lbs)	SO_2 (lbs)
Startup Event			
Combustion Turbines – Syngas	Phase 1	0.0	0.0
Combustion Turbines – Syngas	Phase 2	3006.1	20.2
Combustion Turbines – Syngas	Phase 3	3783.0	42.8
Combustion Turbines – Syngas	Phase 4	21.41	601.99
Shutdown Event			
Combustion Turbines – Syngas	Partial Plant (≤ 5 hrs)	247.4	8.2
Combustion Turbines – Syngas	Entire Plant (> 5 hrs)	247.4	8.2

(2) Total the emissions of SO_2 and NO_X from all pieces of emitting equipment for a calendar month from all startup and shutdown events occurring in that month and add to previous 12-month total; then deduct the total SO_2 and NO_X emissions from the earliest month of the previous 12-month total to determine the current 12-month total.

(3) A description of the startup phases for the combustion turbines during a cold startup of the IGCC plant and a hot startup of an individual gasification train is provided in the following table:

Summary of Startup Phases
Gasification Combustion Turbines – Syngas

Phase	Thermal Oxidizer	Gasification Flare	Combustion Turbines	Cold Start Timeline
1	Initial warm-up	Initial warm-up	Both CT's dormant as Gasification Process goes through initial warm-up	Duration typically 32 hours

Summary of Startup Phases
Gasification Combustion Turbines – Syngas

Phase	Thermal Oxidizer	Gasification Flare	Combustion Turbines	Cold Start Timeline
2	Startup of first SRU, the TGU, and first gas recycle	Venting syngas before first CT comes online and venting acid gas before first SRU comes online	Startup of first CT on natural gas as Gasification Process startup proceeds	Duration typically runs from hour 33 through hour 62 of a cold start
3	Startup of second SRU and second gas recycle unit	Venting syngas before second CT comes online and venting acid gas before second SRU comes online	Transition of first CT to syngas combustion and startup of second CT on natural gas, then transitioning to syngas	Duration typically runs from hour 63 through remainder of a cold start
4	Restart of affected SRU and gas recycle unit	Venting syngas before syngas combustion achieved in CT being restarted and venting acid gas before affected SRU comes online	Restart of a single CT on natural gas, then transitioning to syngas	Durations is typically 5 hours or less

D.7.6 Testing Requirements [326 IAC 2-1.1-11]

(a) Within sixty (60) days after achieving the maximum production rate at which the gasification block will be operated, but no later than 180 days after initial startup of the gasification block, in order to demonstrate compliance with Conditions 7.2, the Permittee shall conduct initial performance tests to measure emissions of SO_2 from the thermal oxidizer during the peak period of SRU startup and during normal mode operation, utilizing methods as approved by the Commissioner.

Permittee shall submit a proposed test protocol to IDEM, OAQ Compliance Section for review at least 35 days prior to the scheduled testing date. Testing shall be conducted in accordance with Section C – Performance Testing. These tests shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration.

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

D.7.7 Record Keeping Requirements

(a) To document compliance with Condition D.7.1(a) and D.7.3, the Permittee shall maintain records of the following:

(1) Monthly emissions of SO_2 and supporting calculation; and

(2) 12-month rolling total of SO_2 emissions;

From all emission units of the IGCC plant with the potential to emit SO_2 .

(b) To document compliance with Condition D.7.1(b) and D.7.4, the Permittee shall maintain records of the following:

(1) Monthly emissions of NO_X and supporting calculation; and

(2) 12-month rolling total of NO_X emissions;

From all emission units of the IGCC plant with the potential to emit NO_X.

(c) To document compliance with Condition D.7.1(c) and D.7.5, the Permittee shall maintain records of the following:

(1) Monthly emissions of SO_2 and NO_X and supporting calculation; and

(2) 12-month rolling total of SO_2 and NO_X emissions;

From all emission units of the IGCC plant with the potential to emit SO_2 and NO_X emissions during startups and shutdowns

(c) To document compliance with Condition D.7.2, the Permittee shall maintain records of the of the stack testing performed as required in D.7.6 showing compliance with the emission limits in D.7.2.

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

D.7.8 Reporting Requirements

A monthly summary of the information to document compliance with Condition D.7.1, D.7.3, D.7.4, and D.7.5 shall be submitted quarterly to the address listed in Section C – General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

SECTION D.8 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

One gasification block with acid gas removal/sulfur recovery, particulate removal and mercury removal consisting of the following:

(1) Two (2) refractory-lined, oxygen-blown, entrained flow gasifiers designated as GASIF1 and GASIF2, permitted in 2008, exhausting through Vents S-5a1 and S-5a2 during startup only.

(2) Two (2) natural gas fired gasification preheaters designated as GPREHEAT1 and GPREHEAT2, permitted in 2008, with a maximum heat input capacity of 19.1 MMBtu/hr each (high heating value basis), exhausting to Vents S-5a1 and S-5a2 during startup only.

(3) One (1) natural gas fired thermal oxidizer designated as THRMOX, permitted in 2008, with a maximum heat input for the pilot of 3.85 MMBtu/hr, exhausting to Stack S-4. The thermal oxidizer will combust waste gas streams from the Sulfur Recovery Unit (SRU) sulfur pit vents and intermittent gas streams for the SRU during startup, shutdown and trip events.

(4) One natural gas fired elevated open flare designated as FLR, permitted in 2008, with a maximum heat input for the pilot of 1.23 MMBtu/hr, exhausting to Stack S-3. An additional heat input of 1.44 MMBtu/hr (natural gas) will be provided to the flare as sweep enrichment gas/flare purge gas. The flare will combust syngas streams from various operations associated with the gasification process during startup, shutdown and trip events.

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

D.8.1 Thermal Oxidizer PSD BACT Limit [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for the natural gas fired thermal oxidizer designated as THRMOX, shall be as follows:

(a) Carbon monoxide (CO) emissions shall not exceed 0.08 lbs/MMBtu.

(b) Particulate matter (PM/PM_{10}/$PM_{2.5}$) emissions shall not exceed 0.0075 lbs/MMBtu (PM filterable, PM_{10} filterable and condensable). (PM_{10} serves as a surrogate for $PM_{2.5}$ throughout this permit.)

(c) Volatile Organic Compound (VOC) emissions shall not exceed 0.005 lbs/MMBtu.

(d) Combustion of natural gas.

(e) Maintenance of equipment in good working order and operation per manufacturer's specifications.

D.8.2 Flare Pilot PSD BACT Limit [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for the natural gas fired flare pilot, designated as FLR, shall be as follows:

(a) Carbon monoxide (CO) emissions shall not exceed 0.08 lbs/MMBtu.

(b) Particulate matter (PM/PM_{10}/$PM_{2.5}$) emissions shall not exceed 0.0075 lbs/MMBtu (PM filterable, PM_{10} filterable and condensable).

(c) Volatile Organic Compound (VOC) emissions shall not exceed 0.005 lbs/MMBtu.

(d) Combustion of natural gas.

(e) Maintenance of equipment in good working order and operation per manufacturer's specifications.

D.8.3 Gasification Pre-heaters PSD BACT Limit [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for each natural gas fired gasifier pre-heater designated as GPREHEAT1 and GPREHEAT2 shall be as follows:

(a) Carbon monoxide (CO) emissions shall not exceed 0.08 lbs/MMBtu.

(b) Particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions shall not exceed 0.0075 lbs/MMBtu (PM filterable, PM_{10} filterable and condensable).

(c) Volatile Organic Compound (VOC) emissions shall not exceed 0.005 lbs/MMBtu.

(d) Combustion of natural gas.

(e) Maximum heat input of each gasifier pre-heater is 19.1 MMBtu/hr.

(f) Maintenance of equipment in good working order and operation per manufacturer's specifications.

D.8.4 Opacity Limitation [326 IAC 2-2] [326 IAC 5-1-2]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity from each natural gas fired gasifier preheater shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of 40 percent (%) 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 non-overlapping integrated averages for a continuous opacity) monitor in a six (6) hour period.

D.8.5 Gasification Block Startups and Shutdowns [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for startup and shutdown of the gasification block of the IGCC plant, comprising the gasifiers, gasifier preheaters (GPREHEAT1 and GPREHEAT2), gas cooling units, acid gas removal (AGR) units, and sulfur recovery units (SRU), shall consist of the following:

(a) Waste gas streams from the sulfur recovery unit shall be vented to the thermal oxidizer, THRMOX, during periods of startups and shutdowns.

(b) Excess syngas and other waste gas streams from the gasification block not routed to the thermal oxidizer shall be routed to the open flare, FLR, during periods of startups and shutdowns.

(c) Emissions from startups, shutdowns, and trips of the gasification block shall not exceed the following annual limits:

Annual Startup and Shutdown Emission Limits			
Equipment	**CO** (tpy)	**PM**[1] (tpy)	**VOC** (tpy)
Thermal Oxidizer	6.8	0.65	0.43
Flare	72.9	4.3	0.58
Gasification Preheaters	5.5	0.5	0.3
Total	85.2	5.45	1.31

[1] PM = PM, $PM_{10}/PM_{2.5}$ (filterable PM, filterable and condensable PM_{10}). PM_{10} serves as a surrogate for $PM_{2.5}$ throughout this permit.

(d) Emissions from startups, shutdowns, and trips of the gasification block shall not exceed the following hourly limits:

Hourly Startup and Shutdown Emission Limits (24-hr average)			
Equipment	**CO** (lbs/hr)	**PM**[1] (lbs/hr)	**VOC** (lbs/hr)
Thermal Oxidizer	5.1	0.45	0.33
Flare	37.2	0.042	0.03

[1] PM = PM, $PM_{10}/PM_{2.5}$ (filterable PM, filterable and condensable PM_{10}). PM_{10} serves as a surrogate for $PM_{2.5}$ throughout this permit.

Compliance Determination Requirements

D.8.6 Thermal Oxidizer Operation

In order to comply with Condition D.8.5, the thermal oxidizer shall be in operation at all times when the sulfur recovery unit / tail gas unit is in operation.

D.8.7 Flare Pilot Flame

The flare must be operated with a flame present at all times when the gasification block is in startup mode and any of the following equipment is in operation: Low Temperature Gas Cooling System, Acid Gas Removal System and Sulfur Recovery Unit.

D.8.8 Gasification Block – Startups and Shutdowns

In order to comply with Condition D.8.5(c), CO, PM and VOC emissions shall be based on a 12 month rolling average determined on a monthly basis using appropriate emission factors and number of specific startup and shutdown events per month.

(a) CO, PM and VOC emissions from startup and shutdown events shall be based on the following calculation method:

(1) Appropriate startup and shutdown emission factor for each piece of emitting equipment in the tables below shall be multiplied by the number of startup and shutdown events of each type per month X 1/2000

(A) Each startup and shutdown emission factor is the maximum pounds of that pollutant that shall be emitted for the specified event.

(i) The operational phases noted as phases 1 through 3 are typical of a cold startup at an IGCC plant. These emission factors represent cumulative emissions as the plant progresses through a cold startup.

(ii) The operational phase noted as phase 4 represents hot startup of an individual IGCC train.

(B) Each trip emission factor is the maximum pounds of that pollutant that shall be emitted for the startup trip event.

Startup and Shutdown Emission Factors Gasification Thermal Oxidizer – Syngas				
Equipment	**Operating Phase**	**CO** (lbs)	**PM**[2] (lbs)	**VOC** (lbs)
Startup Event				
Thermal Oxidizer – Syngas	Phase 1	5.28	0.48	0.352
Thermal Oxidizer – Syngas	Phase 2	155.0	13.99	10.13
Thermal Oxidizer – Syngas	Phase 3	161.9	14.58	10.5
Thermal Oxidizer – Syngas	Phase 4	3.92	0.322	0.231
Equipment Trip B to Thermal Oxidizer	N/A	5.3	0.2	0.2
Tail Gas Unit Trip to Thermal Oxidizer	N/A	4.4	0.1	0.1
Shutdown Event				
Thermal Oxidizer – Syngas	Partial Plant (≤ 5 hrs)	5.9	0.53	0.37
Thermal Oxidizer – Syngas	Entire Plant (> 5 hrs)	13.4	1.2	0.8

Startup and Shutdown Emission Factors Gasification Flare – Syngas				
Equipment	**Operating Phase**	**CO** (lbs)	**PM**[2] (lbs)	**VOC** (lbs)
Startup Event				
Flare – Syngas	Phase 1	3.2	0.29	0.22
Flare – Syngas	Phase 2	477.7	0.95	0.71
Flare – Syngas	Phase 3	898	1.5	1.1
Flare – Syngas	Phase 4	415.6	0.437	0.317
SRU Trip to Flare	N/A	10.3	0.8	0.6
Equipment Trip A to Flare	N/A	14.3	0.8	0.6
CT Trip to Flare	N/A	1120.9	358.2	36.9
Shutdown Event				
Flare – Syngas	Partial Plant (≤ 5 hrs)	670.5	3.2	2.3
Flare – Syngas	Entire Plant (> 5 hrs)	674.8	3.6	2.6

Startup and Shutdown Emission Factors Gasification Preheaters / Gasifiers – Syngas				
Equipment	**Operating Phase**[1]	**CO** (lbs)	**PM**[2] (lbs)	**VOC** (lbs)
Startup Event				
Preheaters / Gasifiers – Syngas	Phase 1	33.0	2.98	2.16
Preheaters / Gasifiers – Syngas	Phase 2	119.9	10.7	7.7
Preheaters / Gasifiers – Syngas	Phase 3	145.0	13.0	9.3

Startup and Shutdown Emission Factors Gasification Preheaters / Gasifiers – Syngas				
Equipment	**Operating Phase**[1]	**CO** (lbs)	**PM**[2] (lbs)	**VOC** (lbs)
Shutdown Event				
Preheaters / Gasifiers – Syngas	Partial Plant (≤ 5 hrs)	NA	NA	NA
Preheaters / Gasifiers – Syngas	Entire Plant (> 5 hrs)	NA	NA	NA

[1] Gasification pre-heaters are only required to be operational while the gasifiers are being brought up to the required temperature. Gasifier preheaters are not required for a hot start-up of an individual gasification train.

[2] PM = PM, PM_{10}/$PM_{2.5}$ (filterable PM, filterable and condensable PM_{10}). PM_{10} serves as a surrogate for $PM_{2.5}$ throughout this permit.

(2) Total the emissions of CO, PM and VOC, respectively, from all pieces of emitting equipment for a calendar month from all startup and shutdown events occurring in that month and add to previous 12-month total; then deduct the total CO, PM and VOC emissions, respectively, from the earliest month of the previous 12-month total to determine the current 12-month total.

(3) A description of the startup phases for the thermal oxidizer and flare devices during a cold startup of the IGCC plant and a hot startup of an individual gasification train is provided in the following table:

Summary of Startup Phases Thermal Oxidizer and Gasification Flare – Syngas			
Phase	**Thermal Oxidizer**	**Gasification Flare**	**Cold Start Timeline**
1	Initial warm-up	Initial warm-up	Duration typically 32 hours
2	Startup of first SRU, the TGU, and first gas recycle	Venting syngas before first CT comes online and venting acid gas before first SRU comes online	Duration typically runs from hour 33 through hour 62 of a cold start
3	Startup of second SRU and second gas recycle unit	Venting syngas before second CT comes online and venting acid gas before second SRU comes online	Duration typically runs from hour 63 through remainder of a cold start
4	Restart of affected SRU and gas recycle unit	Venting syngas before syngas combustion achieved in CT being restarted and venting acid gas before affected SRU comes online	Duration is typically 5 hours or less

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

D.8.9 Thermal Oxidizer Visible Emissions Notations

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

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

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

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

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

D.8.10 Thermal Oxidizer Parametric Monitoring

To demonstrate compliance with Condition D.8.1:

Vendor documentation that certifies the burner is natural gas fired and has a maximum rate heat input of 3.85 MMBtu/hr. No parametric monitoring is required if this information is maintained on file and available for inspection by the agency.

D.8.11 Flare Parametric Monitoring

(a) To demonstrate compliance with Conditions D.8.2 and D.8.7:

(1) The Permittee shall continuously monitor the presence of the flare pilot flame using a thermocouple or any other equivalent device to detect the presence of a flame. For the purpose of this condition, continuous means no less than once per minute; and

(2) The Permittee shall determine flare visible emissions by Reference Method 22

(b) To demonstrate compliance with Condition D.8.5:

The Permittee shall continuously monitor the flow rate, in CFM, of the total gas flow to the flare, including syngas, other waste gases and natural gas. The Permittee shall determine through engineering estimates the heating value of the total flow of gas to the flare within 180 days of initial startup of the gasification block.

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

D.8.12 Record Keeping Requirements

(a) To document compliance with Condition D.8.1, D.8.2, and D.8.3, the Permittee shall maintain records of the following:

(1) Vendor guarantee on maximum heat input capacity of burners associated with the thermal oxidizer, flare and gasifier

(2) Vendor guarantee on lb/MMBtu emission rates for CO, PM and VOC for the thermal oxidizer, flare and gasifier.

(3) Documentation that pipeline natural gas is the only fuel used in the thermal oxidizer, flare and gasifier.

(b) To document compliance with Condition D.8.5, the Permittee shall maintain records of the following:

(1) Monthly emissions of CO, PM and VOC and supporting calculation; and

(2) 12-month rolling total of CO, PM and VOC emissions;

From all emission units of the IGCC plant's Gasification block with the potential to emit CO, PM and VOC emissions during startups and shutdowns

(c) To document compliance with Condition D.8.6 and D.8.9, the Permittee shall maintain records of the following:

(1) Date and time when the SRU, Tail Gas units were operational and confirmation that the thermal oxidizer was in operation.

(2) The Permittee shall maintain a daily record of visible emission notations of the stack exhaust from the thermal oxidizer. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g., the process did not operate that day, etc.).

(d) To document compliance with Condition D.8.7, the Permittee shall maintain records of the following:

(1) Data and time when the gasification blocks gas cooling, acid gas removal and SRU system were operational and documentation that a flare pilot flame was present.

(2) Presence of any visible emissions based on Method 22.

(e) To document compliance with Condition D.8.11(b),the Permittee shall maintain records of the following:

(1) Monthly records of flow rate, in cubic feet per minute (CFM), of the total gas flow to the flare, including syngas, other waste gases and natural gas.

(2) Documentation of engineering estimates that provide the heating value of the total flow of gas to the flare.

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

D.8.13 Reporting Requirements

A monthly summary of the information to document compliance with Condition D.8.12 shall be submitted quarterly to the address listed in Section C – General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

SECTION D.9 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

One power block consisting of the following:

(1) Two (2) combined cycle combustion turbine trains each consisting of a combustion turbine and a heat recovery steam generator, designated as CTHRSG1 and CTHRSG2, permitted in 2008, using diffusion combustors firing either syngas, natural gas, or combined syngas and natural gas, and exhausting to Stacks S-2a and S-2b. The turbine trains use nitrogen diluent injection (to control NO_X) when firing syngas, steam injection when firing natural gas, and nitrogen diluent injection and steam injection when co-firing syngas and natural gas.

Nominal Heat Input Capacity (HHV) for each Combustion Turbine Train	
Fuel	**MMBtu/hr**
Syngas Only	2106
Natural Gas Only	2109
Combined Syngas and Natural Gas	2129

Stacks S-2a and S-2b have continuous emissions monitors (CEMs) for carbon monoxide (CO), nitrogen oxides (NO_X) and sulfur dioxide (SO_2). Mercury (Hg) will be monitored per requirements of 40 CFR Part 60, Subpart Da.

(2) One (1) reheat, condensing steam turbine, permitted in 2008.

(3) One (1) twenty-two (22) cell induced draft cooling tower designated as CT1 – CT22, permitted in 2008, exhausting to Stack S-9. The cooling tower will use a high-efficiency drift eliminator to control particulate emissions.

(4) One (1) natural gas fired auxiliary boiler designated as AUXBLR, permitted in 2008, with a maximum heat input capacity of 300 MMBtu/hr (high heating value basis) and exhausting to Stack S-6.

(5) Two (2) natural gas fired turbine gas conditioning preheaters designated as TPREHEAT1 and TPREHEAT2, permitted in 2008, with a maximum heat input capacity of 5 MMBtu/hr (per unit on a high heating value basis) and exhausting to Stacks S-5b1 and S-5b2 respectively.

(6) One (1) diesel-fired emergency generator designated as EMDSL, permitted in 2008, with a maximum rating of 2200 brake-horsepower (Bhp), exhausting to Stack S-7.

(7) One (1) diesel-fired emergency fire pump designated as FIRPMP, permitted in 2008, with a maximum rating of 420 brake-horsepower (Bhp), exhausting to Stack S-8.

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

D.9.1 Combustion Turbine PSD BACT Limit [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for each combustion turbine train consisting of a combustion turbine and a heat recovery steam generator, designated as CTHRSG1 and CTHRSG2 when firing syngas, natural gas or co-firing syngas with natural gas shall be as follows:

(a) Carbon monoxide (CO) emissions shall not exceed 0.046 lbs/MMBtu (heat input to combustion turbine) based on a twenty-four (24) hour average when combusting syngas or co-firing syngas and natural gas.

(b) Particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions shall not exceed 0.019 lbs/MMBtu (heat input to combustion turbine, PM filterable, PM_{10} filterable and condensable) based on a three (3) hour average when combusting syngas or co-firing syngas and natural gas.

(c) Volatile Organic Compound (VOC) emissions shall not exceed 0.002 lbs/MMBtu (heat input to combustion turbine) based on a three (3) hour average when combusting syngas or co-firing syngas and natural gas or combusting natural gas only.

(d) Carbon monoxide (CO) emissions shall not exceed 0.042 lbs/MMBtu (heat input to combustion turbine) based on a twenty-four (24) hour average when combusting natural gas only.

(e) Particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions shall not exceed 0.009 lbs/MMBtu (heat input to combustion turbine, PM filterable, PM_{10} filterable and condensable) based on a three (3) hour average when combusting natural gas only.

(f) Each combined cycle combustion turbine shall be maintained in good working order and shall be operated using good combustion practices using diffusion combustion technology to minimize CO, PM and VOC emissions

D.9.2 Cooling Tower PSD BACT Limit [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for the twenty-two (22) cell cooling tower designated as CT1 – CT22 shall be as follows:

(a) Particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions shall not exceed 3.2 lbs/hr.

(b) Total dissolved solids less than 5000 mg/l in the recirculating cooling water.

(c) High efficiency drift eliminator with a drift flow rate of less than 0.0005 percent shall be utilized at all times the cooling tower is in operation.

D.9.3 Auxiliary Boiler PSD BACT Limit [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for the natural gas fired auxiliary boiler designated as AUXBLR shall be as follows:

(a) Carbon monoxide (CO) emissions shall not exceed 0.036 lbs/MMBtu.

(b) Particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions shall not exceed 0.0075 lbs/MMBtu. Includes filterable and condensable particulates.

(c) Volatile Organic Compound (VOC) emissions shall not exceed 0.005 lbs/MMBtu.

(d) Maximum heat input of 300 MMBtu/hr and combustion of natural gas only.

(e) Boiler shall be maintained in good working order and shall be operated using good combustion practices.

D.9.4 Turbine Gas Conditioning Preheater PSD BACT Limit [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for each natural gas fired turbine gas conditioning preheater designated as TPREHEAT1 and TPREHEAT2 shall be as follows:

(a) Carbon monoxide (CO) emissions shall not exceed 0.10 lbs/MMBtu.

(b) Particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions shall not exceed 0.0075 lbs/MMBtu.

(c) Volatile Organic Compound (VOC) emissions shall not exceed 0.038 lbs/MMBtu.

(d) Combust natural gas only

(e) Maintenance of the equipment in good working order and operation per manufacturer's specifications.

(f) Maximum heat input of 5.0 MMBtu/hr for each gas conditioning preheater.

D.9.5 Diesel Fired Emergency Generator PSD BACT Limit [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for the diesel fired emergency generator designated as EMDSL shall be as follows:

(a) Emission limitations as defined by NSPS Subpart IIII.

(b) Maintenance of the equipment in good working order and operation per manufacturer's specifications.

D.9.6 Diesel Fired Emergency Fire Pump PSD BACT Limit [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for the diesel fired emergency fire pump designated as FIRPMP shall be as follows:

(a) Emission limitations as defined by NSPS Subpart IIII.

(b) Maintenance of the equipment in good working order and operation per manufacturer's specifications.

D.9.7 Power Block Startups and Shutdowns [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for startups and shutdowns of the power block of the IGCC plant shall be as follows:

(a) Emissions from startups and shutdowns of the power block of the IGCC plant shall not exceed the following annual limits:

Annual Startup and Shutdown Emission Limits			
Equipment	**CO** (tpy)	**PM**[1] (tpy)	**VOC** (tpy)
Aux Boiler	46.0	4.2	3.0
Combustion Turbines	250.8	14.3	48.5
Total	296.8	18.5	51.5

[1] PM = PM, $PM_{10}/PM_{2.5}$ (filterable PM, filterable and condensable PM_{10}). PM_{10} serves as a surrogate for $PM_{2.5}$ throughout this permit.

(b) Emissions from startups and shutdowns of the power block of the IGCC plant shall not exceed the following hourly limits:

Hourly Startup and Shutdown Emission Limits (24-hr average)			
Equipment	**CO** (lbs/hr)	**PM[1]** (lbs/hr)	**VOC** (lbs/hr)
Combustion Turbines	255.0	14.13	49.5

[1] PM = PM, $PM_{10}/PM_{2.5}$ (filterable PM, filterable and condensable PM_{10}). PM_{10} serves as a surrogate for $PM_{2.5}$ throughout this permit.

D.9.8 Auxiliary Boiler Particulate [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating) the PM emissions from auxiliary boiler (AUXBLR) shall be limited to 0.25 pounds per million British thermal units (lbs/MMBtu):

The limit shall be established using the following equation:

$$Pt = 1.09/Q^{0.26}$$

Where: Pt = Pounds of particulate matter emitted per million BTU (lb/MMBtu) heat input
Q = Total source maximum operating capacity rating in million Btu per hour (MMBtu/hr)
Q = 300 MMBtu heat input

Compliance Determination Requirements

D.9.9 Testing Requirements [326 IAC 2-1.1-11][326 IAC 2-2][326 IAC 2-7-6(1)]

(a) **Combustion Turbine Trains:**

(1) **Natural Gas Only:**
Within sixty (60) days after achieving the maximum production rate at which one of the combustion turbine trains will be operated on natural gas, but no later than 180 days after initial startup of the first combustion turbine train on natural gas, in order to demonstrate compliance with Conditions D.9.1 the Permittee shall conduct initial performance test to measure the PM (which includes PM_{10} and $PM_{2.5}$ and filterable and condensable particulates) and VOC of exhaust air from Stacks S-2a and S-2b, utilizing methods as approved by the Commissioner. (Note that PM_{10} is being used throughout this permit as a surrogate for $PM_{2.5}$).

(2) **Syngas Only:**
Within sixty (60) days after achieving the maximum production rate at which one of the combustion turbine trains will be operated on syngas, but no later than 180 days after initial startup of the first combustion turbine train to come online on syngas, in order to demonstrate compliance with Conditions D.9.1 the Permittee shall conduct initial performance test to measure the PM (which includes PM_{10} and $PM_{2.5}$, and filterable and condensable particulates) and VOC of exhaust air from Stacks S-2a and S-2b, utilizing methods as approved by the Commissioner.

(**3**) **Co-firing Syngas and Natural Gas:**
Within sixty (60) days after achieving the maximum production rate at which one of the combustion turbine trains will be operated co-firing syngas and natural gas, but no later than 180 days after initial startup of the first combustion turbine train co-firing syngas and natural gas, in order to demonstrate compliance with Conditions D.9.1 the Permittee shall conduct initial performance test to measure the PM (which includes PM_{10} and $PM_{2.5}$ and filterable and condensable particulates), VOC of exhaust air from Stacks S-2a and S-2b, utilizing methods as approved by the Commissioner.

Testing of only one of the combustion turbines shall be required during the initial performance test and during any subsequent performance test. Subsequent performance tests shall alternate the combustion turbines that are tested for each operating scenario (e.g., if CTHRSG1 is tested for each operating scenario for the initial performance tests, then CTHRSG2 will be tested for each operating scenario for the next set of subsequent performance tests.)

(b) Within sixty (60) days after achieving the maximum production rate at which the auxiliary boiler will be operated, but no later than 180 days after initial startup of the auxiliary boiler, in order to demonstrate compliance with Conditions D.9.3, the Permittee shall conduct initial performance test to measure the CO, PM (which includes PM_{10} and $PM_{2.5}$ and filterable and condensable particulates), and VOC of exhaust air from Stack S-6, utilizing methods as approved by the Commissioner.

(c) Testing shall be conducted in accordance with Section C – Performance Testing. These tests shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. The testing period for the combustion turbine trains may be extended by IDEM upon written request by the Permittee as needed to complete shakedown related to the extensive testing required to verify the new and innovative design of the IGCC process and associated equipment and perform emission testing.

D.9.10 Power Block – Startups and Shutdowns

In order to comply with Condition D.9.7**(a)**, CO, PM and VOC emissions shall be based on a 12-month rolling average, determined on a monthly basis, using appropriate emission factors and number of specific startup and shutdown events per month.

(a) CO, PM and VOC emissions from startup and shutdown events shall be based on the following calculation method:

(1) Appropriate startup and shutdown emission factor for each piece of emitting equipment in the tables below shall be multiplied by the number of startup and shutdown events of each type per month X 1/2000

(A) Each startup and shutdown emission factor is the maximum pounds of that pollutant that shall be emitted for the specified event.

(i) The operational phases noted as phases 1 through 3 are typical of a cold startup at an IGCC plant. These emission factors represent cumulative emissions as the plant progresses through a cold startup.

(ii) The operational phase noted as phase 4 represents hot startup of an individual IGCC train.

(B) Each trip emission factor is the maximum pounds of that pollutant that shall be emitted for the startup trip event.

Startup and Shutdown Emission Factors
Gasification Auxiliary Boiler – Natural Gas

Equipment	Operating Phase[1]	CO (lbs)	PM[2] (lbs)	VOC (lbs)
Startup Event				
Aux. Boiler – Natural Gas	Phase 1	790.6	71.5	51.8
Aux. Boiler – Natural Gas	Phase 2	1210.6	109.5	79.3
Aux. Boiler – Natural Gas	Phase 3	1210.6	109.5	79.3
Shutdown Event				
Aux. Boiler – Natural Gas	Partial Plant (≤ 5 hrs)	NA	NA	NA
Aux. Boiler – Natural Gas	Entire Plant (> 5 hrs)	NA	NA	NA

[1] The Auxiliary Boiler is only required to be in operation during the first 50 hours of a cold startup. The Gasification Auxiliary Boiler is not required for a hot start-up of an individual gasification train.

Startup and Shutdown Emission Factors
Gasification Combustion Turbines – Syngas

Equipment	Operating Phase	CO (lbs)	PM[2] (lbs)	VOC (lbs)
Startup Event				
Combustion Turbines – Syngas	Phase 1	0.0	0.0	0.0
Combustion Turbines – Syngas	Phase 2	5976.2	310.7	1178.0
Combustion Turbines – Syngas	Phase 3	6433.5	367.3	1247.5
Combustion Turbines – Syngas	Phase 4	375.78	40.37	63.77
Shutdown Event				
Combustion Turbines – Syngas	Partial Plant (≤ 5 hrs)	164.6	10.8	29.0
Combustion Turbines – Syngas	Entire Plant (> 5 hrs)	0.0	0.0	0.0

[2] PM = PM, PM_{10}/$PM_{2.5}$ (filterable PM, filterable and condensable PM_{10}). PM_{10} serves as a surrogate for $PM_{2.5}$ throughout this permit.

(2) Total the emissions of CO, PM and VOC, respectively, from all pieces of emitting equipment for a calendar month from all startup and shutdown events occurring in that month and add to previous 12-month total; then deduct the total CO, PM and VOC emissions, respectively, from the earliest month of the previous 12-month total to determine the current 12-month total.

(3) A description of the startup phases for the combustion turbines during a cold startup of the IGCC plant and a hot startup of an individual gasification train is provided in the following table:

Summary of Startup Phases
Gasification Combustion Turbines – Syngas

Phase	Combustion Turbines	Cold Start Timeline
1	Both CT's dormant as Gasification Process goes through initial warm-up	Duration typically 32 hours

Summary of Startup Phases Gasification Combustion Turbines – Syngas		
Phase	**Combustion Turbines**	**Cold Start Timeline**
2	Startup of first CT on natural gas as Gasification Process startup proceeds	Duration typically runs from hour 33 through hour 62 of a cold start
3	Transition of first CT to syngas combustion and startup of second CT on natural gas, then transitioning to syngas	Duration typically runs from hour 63 through remainder of a cold start
4	Restart of a single CT on natural gas, then transitioning to syngas	Durations is typically 5 hours or less

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

D.9.11 Continuous Emissions Monitoring [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), commencing with operation of the each combustion turbine train, a continuous monitoring system for the measurement of oxides of nitrogen (NO_X) emissions, and carbon monoxide (CO) emissions which meets the performance specifications of 326 IAC 3-5-2, shall be installed, calibrated, operated, and maintained for each combustion turbine Stack S-2a and S-2b.

(b) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), commencing with operation of the each combustion turbine train, a continuous monitoring system for the measurement of sulfur dioxide (SO_2) emissions, which meets the performance specifications of 326 IAC 3-5-2, shall be installed, calibrated, operated, and maintained for each combustion turbine Stack S-2a and S-2b.

(c) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), commencing with operation of the auxiliary boiler a continuous monitoring system for the measurement of oxides of nitrogen (NO_X) emissions that meets the performance specifications of 326 IAC 3-5-2, shall be installed, calibrated, operated, and maintained for Stack S-6.

D.9.12 Combustion Turbine Fuel Monitoring

(a) The Permittee shall install, operate and maintain meters to measure and record consumption of syngas and natural gas by each combustion turbine.

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

D.9.13 Record Keeping Requirements

(a) To document compliance with Condition D.9.1, the Permittee shall maintain records of the following:

(1) Performance Testing performed for emissions of PM and VOC.

(2) Continuous Emissions Monitoring Data for emissions of CO.

(b) To document compliance with Condition D.9.2, the Permittee shall maintain records on the following:

(1) Total dissolved solids (TSD) of the coolant water and gallons of coolant water pumped through the cooling tower on a monthly basis.

(2) Documentation that the cooling tower has been equipped with high efficiency mist eliminators.

(c) To document compliance with Condition D.9.3 and D.9.4, the Permittee shall maintain records of the following:

(1) Vendor guarantee of maximum heat input of the auxiliary boiler and gas conditioning heater

(2) Vendor guarantee on lb/MMBtu emission rates for PM and VOC for the auxiliary boiler and gas conditioning heater.

(3) Documentation that pipeline natural gas is the only fuel used in the auxiliary boiler and gas conditioning heater.

(4) Initial compliance test for CO emissions from the Auxiliary Boiler.

(d) To document compliance with Condition D.9.5 and D.9.6, the Permittee shall maintain records of the following:

(1) Documentation that the requirements of NSPS Subpart IIII have been satisfied.

(2) Records on periodic maintenance performed.

(e) To document compliance with Condition D.9.7, the Permittee shall maintain records of the following on the combustion turbines (CTHRSG1 and CTHRSG2) and the auxiliary boiler (AUXBLR):

(1) Monthly emissions of CO, PM and VOC and supporting calculation; and

(2) 12-month rolling total of CO, PM and VOC emissions;

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

D.9.14 Reporting Requirements

A monthly summary of the information to document compliance with Condition D.9.13 shall be submitted quarterly to the address listed in Section C – General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 3326 IAC 2-7-1(34).

SECTION D.10 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Material handling operations consisting of:

(1) Coal receiving and handling system, to be permitted in 2010, except the truck or railcar receiving and unloading station permitted in 2008, using enclosed conveyors consisting of the following equipment:

(A) 1200 ton per hour enclosed coal conveyor with particulate emissions from drop point to active coal pile stacking tube controlled by an insertable dust filter, exhausting to Stack S-1D.

(B) One (1) 1200 ton per hour truck or railcar receiving and unloading station with enclosed drop points and particulate emissions controlled by a baghouse and exhausting to Stack S-1B.

(C) One (1) 1,800 ton per hour reclaim tunnel, using two (2) 900 ton per hour conveyors with enclosed drop points and particulate matter controlled by a baghouse and exhausting to Stack S-2A.

(D) Two (2) 900 ton per hour enclosed coal conveyors with particulate matter from enclosed drop points controlled by insertable dust filters and exhausting to Stacks S-2B and S-2C.

(E) Two (2) enclosed coal bunkers with a total loading capacity of 1800 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S- 3A and S-3B.

(2) Lime and soda ash handling system, to be permitted in 2010:

(A) Transfer of lime from truck or railcar by a closed pneumatic conveyor to two (2) lime storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4A and S-4B.

(B) Transfer of soda ash from truck or railcar by a closed pneumatic conveyor to two (2) soda ash storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4C and S- 4D.

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

D.10.1 Coal Handling and Lime and Soda Ash Handling Particulate Matter BACT Requirements [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for coal receiving and unloading station emissions exhausting to Stack S-1B, coal reclaim tunnel conveyor emissions exhausting to stack S-2A, coal conveyor emissions exhausting to Stacks S-1D, S-2B and S-2C, coal bunker emissions exhausting to Stacks S-3A and S-3B, and lime handling emissions exhausting to Stacks S-4A and S-4B, and Soda Ash handling emissions exhausting to Stacks S-4C and S-4D shall be as follows:

(a) Best management practices.

(b) PM emissions from the high efficiency baghouses, insertable dust filters and bin vent dust collectors shall not exceed a grain loading of 0.003 grains per dry standard cubic foot (gr/dscf).

(c) $PM/PM_{10}/PM_{2.5}$ emissions shall not exceed;

(A) 0.66 lbs/hr for the reclaim tunnel baghouse (Stack S-2A);

(B) 0.34 lbs/hr for the coal receiving and unloading station baghouse (Stack S-1B);

(C) 0.064 lb/hr for the bin vent dust collector associated with the coal bunker, identified as coal bunker #1 (Stack S-3A);

(D) 0.064 lb/hr for the bin vent dust collector associated with the coal bunker, identified as coal bunker #2 (Stack S-3B);

(E) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-002 Head Chute (Stack S-1D);

(F) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-003A Head Chute (Stack S-2B);

(G) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-003B Head Chute (Stack S-2C);

(H) 0.019 lb/hr for the bin vent dust collector associated with the lime silo, identified as Lime Silo #1(Stack S-4A);

(I) 0.019 lb/hr for the bin vent dust collector associated with the lime silo, identified as Lime Silo #2 (Stack S-4B);

(J) 0.019 lb/hr for the bin vent dust collector associated with the soda ash silo #1 (Stack S-4C); and

(K) 0.019 lb/hr for the bin vent dust collector associated with the soda ash silo #2 (Stack S-4D).

D.10.2 Particulate Emissions Limitation for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emissions from the coal receiving and handling and lime and soda ash handling shall not exceed the pounds per hour rate (E) when operating at a process weight of (P) tons per hour as determined by the following equation:

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

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

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

Particulate Emission Limitations for Manufacturing Processes			
Emission Point	**Unit Description**	**Process Weight Rate (TPH)**	**E (lb/hr)**
Stack S-2A	Reclaim Tunnel	1800	85.4
Stack S-1B	Coal receiving and unloading station	1200	80
Stack S1-D	Conveyor MH-002 Head Chute	1200	80
Stack S-2B	Conveyor MH-003A Head Chute	900	76.2
Stack S-2C	Conveyor MH-003B Head Chute	900	76.2
Stack S3-A	Coal Bunker #1	1800	85.4
Stack S-3B	Coal Bunker #2	1800	85.4
Stack S-4A	Lime Silo #1	46	43.8
Stack S-4B	Lime Silo #2	46	43.8
Stack S-4C	Soda Ash Silo #1	46	43.8
Stack S-4D	Soda Ash Silo #2	46	43.8

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

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for the baghouses.

Compliance Determination Requirements

D.10.4 Particulate Control [326 IAC 2-7-6(6)][326 IAC 6-3-2][326 IAC 2-2]

(a) Except as otherwise provided by statute or rule or in this permit, the baghouses, dust collectors and dust filters for PM control shall be in operation and control emissions at all times the associated coal, reclaim tunnel, coal receiving and unloading station, coal conveyors, bunkers and lime and soda ash facilities are in operation.

(b) Vendor guarantee that each baghouse, dust collectors and dust filters meets a grain outlet loading of 0.003 grains/dscf.

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

(a) Within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of the coal reclaim operations, in order to demonstrate compliance with Condition D.10.1, the Permittee shall conduct initial performance test to measure the PM (which includes PM_{10} and $PM_{2.5}$ and filterable and condensable particulates), of exhaust air from Stack S-2A, utilizing methods as approved by the Commissioner.

(b) Within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of the coal receiving and unloading station, in order to demonstrate compliance with Condition D.10.1, the Permittee shall conduct initial performance test to measure the PM (which includes PM_{10} and $PM_{2.5}$ and filterable and condensable particulates), of exhaust air from Stack S-1B, utilizing methods as approved by the Commissioner.

(c) Within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of coal conveying operations, in order to demonstrate compliance with Condition D.10.1, the Permittee shall conduct initial performance test to measure the PM (which includes PM_{10} and $PM_{2.5}$ and filterable and condensable particulates), of exhaust air from, Stacks S-1D, S-2B and S-2C, utilizing methods as approved by the Commissioner.

(d) Within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of the coal bunker operations, in order to demonstrate compliance with Condition D.10.1, the Permittee shall conduct initial performance test to measure the PM (which includes PM10 and PM2.5 and filterable and condensable particulates), of exhaust air from Stacks S-3A and S-3B, utilizing methods as approved by the Commissioner.

(e) Within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of the lime and soda ash handling operations, in order to demonstrate compliance with Condition D.10.1, the Permittee shall conduct initial performance test to measure the PM (which includes PM_{10} and $PM_{2.5}$ and filterable and condensable particulates), of exhaust air from Stack S4-A, S-4B, S-4C and S-4D, utilizing methods as approved by the Commissioner.

Testing shall be conducted in accordance with Section C – Performance Testing. These tests shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration.

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

D.10.6 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

(a) Visible emission notations of each baghouse, dust collector, and dust filter exhausts shall be performed once per week during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

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

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

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

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

(f) If any emissions are observed from the coal unloading station doorways and drop points, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances, and Reports. Visible emissions that do not violate 326 IAC 6-4 (Fugitive Dust Emissions) or an applicable opacity limit is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

(g) If abnormal emissions are observed at any baghouse exhaust, 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 326 IAC 6-4 (Fugitive Dust Emissions) or an applicable opacity limit is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

D.10.7 Baghouse Parametric Monitoring [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

(a) The Permittee shall record the pressure drop across each of the baghouses, dust collectors and dust filters used in conjunction with the coal reclaim operations, receiving and unloading station, coal conveyors, coal bunkers and lime and soda ash facilities at least once per week when the facilities are in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range of 3.0 and 6.0 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. 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.

(b) The instrument used for determining the pressure shall comply with Section C - Instrument Specifications, and shall be calibrated in every 6 months. The specifications shall be available on site with the Preventive Maintenance Plan.

D.10.8 Broken or Failed Bag Detection [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

(a) For a single compartment baghouse controlling emissions from a process operated continuously, a failed unit and the associated process shall be shut down immediately until the failed unit has been repaired or replaced. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

(b) For a single compartment baghouses controlling emissions from a batch process, the feed to the process shall be shut down immediately until the failed unit has been repaired or replaced. The emissions unit shall be shut down no later than the completion of the processing of the material in the coal transfer system. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

Bag failure can be indicated by a significant drop in the baghouse's pressure reading with abnormal visible emissions, by an opacity violation, or by other means such as gas temperature, flow rate, air infiltration, leaks, dust traces or triboflows.

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

D.10.9 Record Keeping Requirements

(a) In order to document compliance with Condition D.10.6 - Visible Emissions Notations, the Permittee shall maintain records of the visible emission notations of the transfer points, baghouse dust collector and dust filter exhausts and railcar unloading stations. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).

(b) In order to document compliance with Condition D.10.7 - Baghouse Parametric Monitoring, the Permittee shall maintain records of the pressure drop across each baghouse dust collector and dust filter. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).

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

SECTION D.11 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Fugitive dust emissions consisting of:

(1) Coal storage piles including one (1) inactive coal pile identified as CP_IN and one (1) active coal pile identified as CP_AC.

(2) Slag storage pile and slag handling

(3) Paved roads/Parking Areas

Emission Limitations and Standards [326 IAC 2-7-5(1)][326 IAC 2-2-3]

D.11.1 Coal Storage Pile PSD BACT Requirements [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for fugitive emissions of $PM/PM_{10}/PM_{2.5}$ from coal storage piles designated as CP_IN and CP_AC shall be:

(a) Best management practices

(b) Wet suppression techniques shall be used on an as-needed basis to minimize fugitive dust.

(c) Coal compaction techniques shall be used to further control PM.

D.11.2 Slag Storage Pile and Slag Handling PSD BACT Requirements [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for fugitive emissions of $PM/PM_{10}/PM_{2.5}$ emissions from the slag storage pile and handling operations shall be:

(a) Best management practices

(b) Wet suppression techniques shall be used on an as-needed basis to minimize fugitive dust.

(c) Water added to slag for processing shall be used for added PM control.

D.11.3 Paved Roads/Parking Areas PSD BACT Requirements [326 IAC 2-2]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for fugitive emissions of $PM/PM_{10}/PM_{2.5}$ emissions from paved roads shall be:

(a) Best management practices

(b) The visible emissions from paved roads/parking areas shall not exceed 15% opacity.

(c) Vehicle speeds on paved roads shall be limited to 20 mph.

(d) Wet suppression techniques shall be used on an as-needed basis, but at a minimum of once per week except when ambient air temperature is below 32°F.

(e) Removal of significant deposits of soil on paved roads and investigation and proper clean-up of incidents of material spillage on paved roads that may create fugitive dust.

Compliance Determination Requirements [326 IAC 2-1.1-11]

D.11.4 Fugitive Dust Control Plan [326 IAC 2-2]

To comply with Conditions D.11.1, D.11.2 and D.11.3, the Permittee shall maintain, update, comply, and implement its Fugitive Dust Control Plan.

(a) At a minimum, the fugitive dust plan shall address any fugitive emissions from paved roads, parking areas, and wind erosion of coal/slag piles.

(b) The job title and telephone number on site of the person responsible for implementing the fugitive dust plan shall be provided to IDEM, OAQ.

(c) Paved roads/parking areas shall be controlled by the use of water flushing and shall be performed on an as needed basis.

(d) Coal and slag storage piles shall be watered on an as-needed basis to eliminate wind erosion.

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

D.11.5 Paved Roads/Parking Areas [326 IAC 2-2]

The Permittee shall perform the following opacity evaluations once per month:

(a) The opacity from paved roads/parking areas shall be the average of twelve (12) instantaneous opacity readings, taken for four (4) vehicle passes, consisting of three (3) opacity readings for each vehicle pass.

(b) The three (3) opacity readings for each vehicle pass shall be taken as follows:

(i) The first will be taken at the time of emission generation.
(ii) The second will be taken five (5) seconds later.
(iii) The third will be taken five (5) seconds later or ten (10) seconds after the first.

(c) The three (3) readings shall be taken at a point of maximum opacity.

(d) The readings shall be taken at least fifteen (15) feet, but no more than one-fourth (1/4) mile, from the plume and at approximately right angles to the plume.

(e) Each reading shall be taken approximately four (4) feet above the surface of the paved road/parking area.

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

D.11.6 Record Keeping Requirements

(a) The Permittee shall maintain records of the activities required by Conditions D.11.1, D.11.2 and D.11.3 and make available upon request to IDEM, OAQ and the USEPA.

(b) Records necessary to demonstrate compliance shall be available within 30 days of the end of each compliance period.

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

SECTION E TITLE IV ACID RAIN PROGRAM CONDITIONS

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Units at the Existing Coal-Fired Power Plant to be Retired prior to operation of the IGCC Plant:

(a) One (1) No. 2 Fuel oil fired boiler, identified as Boiler No. 6-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr) and exhausting to stack 6-1.

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 7-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 7-1. Stack 7-1 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

(c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 7-2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 7-2. Stack 7-2 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

(d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 8-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 8-1. Stack 8-1 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

Acid Rain Program

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

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

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

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

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

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

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

E.3 Acid Rain Permit Applications [326 IAC 2-7-11] [326 IAC 2-7-12] [326 IAC 21] [40 CFR 72]

Pursuant to 40 CFR 72.30, Duke Energy Indiana shall submit a complete Acid Rain permit application for each new unit at least twenty-four (24) months before the date on which the unit commences operation, and shall not operate the new unit without a permit that states its Acid Rain program requirements.

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

ORIS Code: 1004

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

Emission Units at the Existing Coal-Fired Power Plant to be Retired prior to operation of the IGCC Plant:

(a) One (1) No. 2 fuel oil-fired boiler, identified as Boiler No. 6-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr) and exhausting to stack 6-1.

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 7-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 7-1. Stack 7-1 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

(c) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 7-2, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 7-2. Stack 7-2 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

(d) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 8-1, construction commenced prior to August 17, 1971, with a nominal heat input capacity of 510 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, and exhausting to stack 8-1. Stack 8-1 has Continuous Emissions Monitors (CEMs) for Oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) and a continuous opacity monitor (COM).

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

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

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

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

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

(b) The NO_X budget units subject to this NO_X budget permit are: Boiler Units 6-1, 7-1, 7-2, and 8-1.

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

(a) The Permittee and, to the extent applicable, the NO_X authorized account representative of Boilers 6-1, 7-1, 7-2, and 8-1 shall comply with the monitoring requirements of 40 CFR 75 and 326 IAC 10-4-12.

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

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

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

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

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

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

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

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

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

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

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

(g) Upon recordation by the U.S. EPA under 326 IAC 10-4-10, 326 IAC 10-4-11, or 326 IAC 10-4-13, every allocation, transfer, or deduction of a NO_X allowance to or from each boiler's compliance account or the overdraft account is deemed to amend automatically, and become a part of, this permit by operation of law without any further review.

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

The Permittee, for each boiler that has excess emissions in any ozone control period shall do the following:

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

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

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

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

(a) The account certificate of representation for the NO_X authorized account representative for the source and boilers 6-1, 7-1, 7-2, and 8-1 and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with 326 IAC 10-4-6(h). The certificate and documents shall be retained either on site at the source or at a central location within Indiana for those owners or operators with unattended sources beyond the five (5) year period until the documents are superseded because of the submission of a new account certificate of representation changing the NO_X authorized account representative.

(b) All emissions monitoring information, in accordance with 40 CFR 75 and 326 IAC 10-4-12, provided that to the extent that 40 CFR 75 and 326 IAC 10-4-12 provide for a three (3) year period for record keeping, the three (3) year period shall apply.

(c) Copies of all reports, compliance certifications, and other submissions and all records made or required under the NO_X budget trading program.

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

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

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

(a) The NO_X authorized account representative of each of boilers 6-1, 7-1, 7-2, and 8-1 shall submit the reports and compliance certifications required under the NO_X budget trading program, including those under 326 IAC 10-4-8, 326 IAC 10-4-12, or 326 IAC 10-4-13.

(b) Pursuant to 326 IAC 10-4-4(e) and 326 IAC 10-4-6(e)(1), each submission shall include the following certification statement by the NO_X authorized account representative: “I am authorized to make this submission on behalf of the owners and operators of the NO_X budget sources or NO_X budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(c) Where 326 IAC 10-4 requires a submission to IDEM, OAQ, the NO_X authorized account representative shall submit required information to:

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

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

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

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

The Permittee shall be liable as follows:

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

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

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

(d) Boilers 6-1, 7-1, 7-2, and 8-1 shall meet the requirements of the NO_X budget trading program.

(e) Any provision of the NO_X budget trading program that applies to boilers 6-1, 7-1, 7-2, and 8-1, including a provision applicable to the NO_X authorized account representative, shall also apply to the Permittee.

(f) Any provision of the NO_X budget trading program that applies to boilers 6-1, 7-1, 7-2, 8-1, including a provision applicable to the NO_X authorized account representative, shall also apply to the Permittee. Except with regard to the requirements applicable to units with a common stack under 40 CFR 75 and 326 IAC 10-4-12, the owners and operators and the NO_X authorized account representative of one (1) NO_X budget unit shall not be liable for any violation by any other NO_X budget unit of which they are not owners or operators or the NO_X authorized account representative and that is located at a source of which they are not owners or operators or the NO_X authorized account representative.

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

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

F.10 Permit Requirements [326 IAC 10-4-7]

Pursuant to 326 IAC 10-4-7(B)(1)(b), as a NO_X budget source required to have a Part 70 operating permit under 326 IAC 2-7, Duke Energy Indiana is required to submit a complete NO_X budget permit application for the IGCC plant at least two hundred seventy (270) days prior to the date on which any of the new NO_X budget units commences operation.

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

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

The power block includes the following, among other emission units:

(1) Two (2) combined cycle combustion turbine trains each consisting of a combustion turbine and a heat recovery steam generator, designated as CTHRSG1 and CTHRSG2, permitted in 2008, using diffusion combustors firing either syngas, natural gas, or combined syngas and natural gas, and exhausting to Stacks S-2a and S-2b. The turbine trains use nitrogen diluent injection (to control NO_X) when firing syngas, steam injection when firing natural gas, and nitrogen diluent injection and steam injection when co-firing syngas and natural gas.

Nominal Heat Input Capacity (HHV) for each Combustion Turbine Train	
Fuel	**MMBtu/Hr**
Syngas Only	2106
Natural Gas Only	2109
Combined Syngas and Natural Gas	2129

Stacks S-2a and S-2b have continuous emissions monitors (CEMs) for carbon monoxide (CO), nitrogen oxides (NO_X) and sulfur dioxide (SO_2). Mercury (Hg) will be monitored per requirements of 40 CFR Part 60, Subpart Da.

Under the NSPS for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, (40 CFR 60, Subpart Da), these emission units are considered to be new integrated gasification combined cycle electric utility steam generating units.

G.1.1 General Provisions Relating to NSPS Subpart Da [326 IAC 12-1] [40 CFR 60, Subpart A]

The provisions of 40 CFR 60 Subpart A - General Provisions, which are incorporated as 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR 60 Subpart Da.

G.1.2 NSPS for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 [40 CFR Part 60, Subpart Da]

Pursuant to 40 CFR Part 60, Subpart Da, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart Da, upon startup of the affected units, as follows:

§ 60.40Da Applicability and designation of affected facility.

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

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

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

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

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

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

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

(4) Intentionally omitted

(c) Intentionally omitted

(d) Intentionally omitted

§ 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, refer to §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 from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry FGD technology include, but are not limited to, lime and sodium.

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

Electric utility combined cycle gas turbine means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW 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 40 CFR 51.24.

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

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

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

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

Integrated gasification combined cycle electric utility steam generating unit or IGCC electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No coal is directly burned in the unit during operation.

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

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

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

Natural gas means:

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

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

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

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

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

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

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

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

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

(1) For particulate matter (PM) is:

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

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

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

(3) For nitrogen oxides (NO_X) is:

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

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

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

Potential electrical output capacity means 33 percent of the maximum design heat input capacity of the steam generating unit, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr (e.g., a steam generating unit with a 100MW (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, liquefied 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.

§ 60.42Da Standard for particulate matter (PM).

(a) Intentionally omitted.

(b) On and after the date the initial PM performance test is completed or required to be completed under §60.8, which ever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

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

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

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

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

§ 60.43Da Standard for sulfur dioxide (SO_2).

(a) Intentionally omitted.

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

(c) Intentionally omitted.

(d) Intentionally omitted.

(e) Intentionally omitted.

(f) Intentionally omitted..

(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=(340x+520y)/100 and

%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:

Es=(340x+520y)/100 and

%Ps=(10x+30y)/100

where:

Es = Prorated SO_2emission limit (ng/J heat input),

%Ps = 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) Intentionally omitted.

(k) Intentionally omitted.

§ 60.44Da Standard for nitrogen oxides (NO_X).

(a) On and after the date on which the initial performance test 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_X emission 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_X standards and NO_X monitoring 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_X reduction requirement.*

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

(b) Intentionally omitted.

(c) Except as provided under paragraph (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=[86w+130x+210y+260z+340 v]/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) Intentionally omitted.

(e) Intentionally omitted.

(f) Intentionally omitted.

§ 60.45Da Standard for mercury.

(a) Intentionally omitted.

(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 which 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.

Intentionally omitted.

§ 60.48Da Compliance provisions.

(a) Intentionally omitted.

(b) Intentionally omitted.

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

(d) Intentionally omitted.

(e) After the initial performance test required under §60.8, compliance with the SO_2 emission limitations and percentage reduction requirements under §60.43Da and the NO_X emission limitations under §60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both 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_2 emission limitations and percent reduction requirements under §60.43Da and the NO_X emission 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_X emission 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_X only), or emergency conditions (SO_2) only.

(2) Compliance with applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days.

(3) Compliance with applicable daily average PM emission limitations is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. Averages are only calculated for boiler operating days that have valid data for at least 18 hours of unit operation during which the standard applies. Instead, the valid hourly emission rates are averaged with the next boiler operating day with 18 hours or more of valid PM CEMS data to determine compliance.

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

(i) Intentionally omitted.

(j) Intentionally omitted.

(k) Intentionally omitted.

(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_2 emissions as 1.660 x 10-7 lb/scf-ppm times the average hourly SO_2 output concentration in ppm (measured according to the provisions of §60.49Da(b)), times the average hourly flow rate (measured according to the provisions of §60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)). Alternatively for oil-fired and gas-fired units, SO_2 emissions may be calculated by multiplying the hourly SO_2 emission rate (in lb/MMBtu), measured by the CEMS required under 60.49Da, by the hourly heat input rate (measured according to the provisions of § 60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)).

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

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

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in 60.42Da(c)(2) or (d) by the applicable date specified in § 60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months of the date of the prior performance test. You must conduct each performance test according to the requirements in § 60.8 using the test methods and procedures in § 60.50Da.

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

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

(ii) You must comply with the quality assurance requirements in paragraphs (o)(4)(ii)(A) through (E) of this section.

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

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

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

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

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

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

(iv) You must evaluate the preceding 24-hour average opacity level measured by the COMS each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the measured 24-hour average opacity emission level is greater than the baseline opacity level determined in paragraph (o)(2)(iii) of this section, you must
initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high opacity incident and take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the measured 24-hour average opacity to a level below the baseline opacity level.

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

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

(3) Intentionally omitted.

(4) Intentionally omitted.

(5) An owner or operator of a modified affected source electing to meet the emission limitations in § .42Da(d) shall determine the percent reduction in PM by using the emission rate for PM determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

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

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a CEMS measuring PM. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation

of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

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

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

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

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

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

(ii) [Reserved]

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

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

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

§ 60.49Da Emission monitoring.

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere,. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO_2 control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(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_2 emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of appendix A of this part may be used to determine potential 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_2 continuous emissions monitoring system (CEMS) according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of § 75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used to meet the requirements of this section provided that:

(i) A CO_2 or O_2 continuous monitoring system is installed, calibrated, maintained and operated at the same location, according to paragraph (d) of this section; and

(ii) For sources subject to an SO_2 emission limit in lb/MMBtu under § 60.43Da:

(A) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously; and

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

(iii) The reporting requirements of § 60.51Da are met. The SO_2 and CO_2 (or O_2) data reported to meet the requirements of § 60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2 data have been bias adjusted according to the procedures of part 75 of this chapter.

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_X emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a NO_X emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.51Da. Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or carbon dioxide (CO_2) content of the flue gases at each location where SO_2 or NO_X emissions are monitored. For affected facilities subject to a lb/MMBtu SO_2 emission limit under § 60.43Da, if the owner or operator has installed and certified a CO_2 or O_2 monitoring system according to § 75.20(c) of this chapter and Appendix A to part 75 of this chapter and the monitoring system continues to meet the applicable quality-assurance provisions of § 75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used together with the part 75 SO_2 concentration monitoring system described in paragraph (b) of this section, to determine the SO_2 emission rate in lb/MMBtu. SO_2 data used to meet the requirements of § 60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

(f)(1) Intentionally omitted.

(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_2 concentration at the same location as the SO_2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

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

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

(4) The procedures in Method 19 of appendix A of this part shall be used to compute each 1-hour average concentration in ng/J (1b/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_X concentrations, respectively.

(2) SO_2 or NO_X (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a CEMS for measuring opacity is between 60 and 80 percent. Span Values for a CEMS measuring NO_X shall be determined using one of the following procedures:

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

Fossil fuel	Span value for nitrogen oxides (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_X span values determined according to section 2.1.2 in appendix A to Part 75 of this chapter. (4) All span values computed under paragraph (i)(3)(iii) 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_2 CEMS at the inlet to the SO_2 control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the SO_2 control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired. For affected facilities determining span values under paragraph (i)(3)(ii) of this section, SO_2 span values shall be determined according to section 2.1.1 in appendix A to part 75 of this chapter.

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

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

(2) For Method 7 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) Intentionally omitted.

(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) Intentionally omitted.

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in §60.45Da shall install and operate a CEMS to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to §75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of each CEMS according to the requirements of §60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in §60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in §60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (i.e., valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in §72.2 of this chapter) to monitor Hg concentration, according to the procedures described in §75.15 of this chapter and appendix K to part 75 of this chapter.

(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of §75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in §75.11(b) or §75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (e.g., calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of §60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of §60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing recordkeeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under §60.42Da(c)(1) shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected source demonstrating compliance with the input-based emission limitation under §60.42Da(c)(2) may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) An owner or operator of an affected source that meets the conditions in either paragraph (u)(1), (2), or (3)of this section is exempted from the continuous opacity monitoring system requirements in paragraph (a) of this section and the monitoring requirements in §60.48Da(o).

(1) A CEMS for measuring PM emissions is used to demonstrate continuous compliance on a boiler operating day average with the emissions limitations under §60.42Da(a)(1) or §60.42Da(c)(2) and is installed, certified, operated, and maintained on the affected source according to the requirements of paragraph (v) of this section; or

(2) The affected source burns only gaseous fuels and does not use a post-combustion technology to reduce emissions of SO_2 or PM; or

(3) The affected source does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (u)(3)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (u)(3)(i)(A) through (D) of this section.

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

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

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

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

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

(iii) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 1.4 lb/MWh, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 1.4 lb/MWh or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (u)(3) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 1.4 lb/MWh, and the date, time, and description of the corrective action.

(v) The owner or operator of an affected facility using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (v)(1) through (v)(3).

(1) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of §60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each relative accuracy test run of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using the following test methods.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For O_2 (or CO_2), EPA Reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(w)(1) Except as provided for under paragraphs (w)(2), (w)(3), and (w)(4) of this section, the SO_2, NO_X, CO_2, and O_2 CEMS required under paragraphs (b) through (d) of this section shall be installed, certified, and operated in accordance with the applicable procedures in Performance Specification 2 or 3 in appendix B to this part or according to the procedures in appendices A and B to part 75 of this chapter. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in appendix F to this part, and a data assessment report (DAR), prepared according to section 7 of Procedure 1 in appendix F to this part, shall be submitted with each compliance report required under § 60.51Da., the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(2) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For all required CO_2 and O_2 CEMS and for SO_2 and NO_X CEMS with span values greater than 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F of this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to SO_2 and NO_X span values less than 100 ppm;

(3) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For all required CO_2 and O_2 CEMS and for SO_2 and NO_X CEMS with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter 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_X span values less than or equal to 30 ppm;

(4) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For SO_2, CO_2, and O_2 CEMS and for NO_X CEMS, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2 (regardless of the SO_2 emission level during the RATA), and for NO_X when the average NO_X emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu; (5) If the owner or operator elects to implement the alternative data assessment procedures described in paragraphs (w)(2) through (w)(4) of this section, each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by paragraphs (w)(2) through (w)(4) of this section.

§ 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for SO_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_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentrations at all traverse points.

(3) Method 9 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_2 standards in §60.43Da as follows:

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

$\%Ps=[(100—\%R_f)\ (100—\%R_g)]/100$

where:

%Ps=percent of potential SO_2 emissions, percent.

%Rf=percent reduction from fuel pretreatment, percent.

%Rg=percent reduction by SO_2 control system, percent.

(2) The procedures in Method 19 of appendix A of this part may be used to determine percent reduction (%Rf) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and fly ash interactions. This determination is optional.

(3) The procedures in Method 19 of appendix A of this part shall be used to determine the percent SO_2 reduction (%Rg) of any SO_2 control system. Alternatively, a combination of an “as fired” fuel monitor and emission rates measured after the control system, following the procedures in Method 19 of appendix A of this part, may be used if the percent reduction is calculated using the average emission rate from the SO_2 control device and the average SO_2 input rate from the “as fired” fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate.

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

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

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

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

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

(1) For Method 5 or 5B of appendix A of this part, Method 17 of appendix A of this part may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of §§2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after wet FGD systems. Method 17 of appendix A of this part shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The Fc factor (CO_2) procedures in Method 19 of appendix A of this part may be used to compute the emission rate of particulate matter under the stipulations of §60.46(d)(1). The CO_2 shall be determined in the same manner as the O_2 concentration.

(f) Electric utility combined cycle gas turbines are performance tested for PM, SO_2, and NO_X using the procedures of Method 19 of appendix A of this part. The SO_2 and NO_X emission rates from the gas turbine used in Method 19 of appendix A of this part calculations are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

(g) Intentionally omitted.

(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 8in 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 Hg 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, Bws = 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 7of this section, (lb); and

n = The number of unit operating hours in the month with valid CE and electrical output data, excluding hours of unit startup, shutdown and malfunction.

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 9, below. For a cogeneration unit, use Equation 5 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \qquad \text{(Eq. 9)}$$

Where:

ER = Monthly Hg emission rate, (lb/MWh);

M = Total mass of Hg emissions for the month, from Equation 8, above, (lb); and

P = Total electrical output for the month, for the hours used to calculate M, (MWh).

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 10 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=1}^{12}(ER_i \times n_i)}{\sum_{i=1}^{12} n_i} \qquad \text{(Eq. 10)}$$

Where:

E_{avg} = Weighted 12-month rolling average Hg emission rate, (lb/MWh)

$(ER)_i$ = Monthly Hg emission rate, for month “i”, (lb/MWh); and

n = The 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 3 through 5 of this section, except that for a particular pair of sorbent traps, Ch in Equation 3 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° or $HgCl_2$) standards. The four quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using $HgCl_2$ standards, as described in section 8.3 of Performance Specification 12–A in appendix B to this part (note: Hg° standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

§ 60.51Da Reporting requirements.

(a) For SO_2, NO_X, PM, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For SO_2 and NO_X the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average SO_2 and NO_X emission rates (ng/J or lb/MMBtu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of SO_2 for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_X only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(9) Description of any modifications to the CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of §60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates ($_{no}$) and inlet emission rates ($_{ni}$) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates ($_{so}$) and inlet emission rates ($_{si}$) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (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_2 emission standard under §60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of §60.50Da and Method 19 of appendix A of this part; and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, SO_2 or NO_X emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) For Hg, the following information shall be reported to the Administrator:

(1) Company name and address;

(2) Date of report and beginning and ending dates of the reporting period;

(3) The applicable Hg emission limit (lb/MWh); and

(4) For each month in the reporting period:

(i) The number of unit operating hours;

(ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;

(iii) The monthly Hg emission rate (lb/MWh);

(iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and

(v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

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

(1) The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

§ 60.52Da Recordkeeping requirements.

The owner or operator of an affected facility subject to the emissions limitations in §60.45Da or §60.46Da 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).

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

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

(4) One (1) natural gas fired auxiliary boiler designated as AUXBLR, permitted in 2008, with a maximum heat input capacity of 300 MMBtu/hr (high heating value basis) and exhausting to Stack S-6.

Under the NSPS for Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Db), the auxiliary boiler is considered to be a natural gas fired steam generating unit commencing construction after February 28, 2005.

G.2.1 General Provisions Relating to NSPS Subpart Db [326 IAC 12-1] [40 CFR 60, Subpart A]

The provisions of 40 CFR 60 Subpart A - General Provisions, which are incorporated as 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR 60 Subpart Db.

G.2.2 NSPS for Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60, Subpart Db]

Pursuant to 40 CFR Part 60, Subpart Db, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart Db, upon startup of the affected unit, as follows:

§ 60.40b Applicability and delegation of authority.

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

(b) Intentionally omitted.

(c) Intentionally omitted.

(d) Intentionally omitted.

(e) Intentionally omitted.

(f) Intentionally omitted.

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

(1) Section 60.44b(f).

(2) Section 60.44b(g).

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

(h) Intentionally omitted.

(i) Intentionally omitted.

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

§ 60.41b Definitions.

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

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

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide CO_2 levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

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

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388–(incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

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

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

Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

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

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

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference—see §60.17).

Dry flue gas desulfurization technology 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 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 flue gas desulfurization technology include but are not limited to lime and sodium.

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

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

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

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

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

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

Gaseous fuel means any fuel that is present as a gas at ISO conditions.

Gross output means the grouss useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

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

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

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

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

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

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

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

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

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

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

Natural gas means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835(incorporated by reference, see §60.17).

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

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

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

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

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

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

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396(incorporated by reference, see §60.17).

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

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

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

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005, very low sulfur oil means an oil that contains no more than 0.3 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input.

Wet flue gas desulfurization technology 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 gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.

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

§ 60.42b Standard for sulfur dioxide (SO_2).

(a) Intentionally omitted.

(b) Intentionally omitted.

(c) Intentionally omitted.

(d) Intentionally omitted.

(e) Intentionally omitted.

(f) Intentionally omitted.

(g) Intentionally omitted.

(h) Intentionally omitted.

(i) Intentionally omitted.

(j) Intentionally omitted.

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(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2 emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

(2) Units firing only very low sulfur oil and/or a mixture of gaseous fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in paragraph 60.42b(k)(1).

(3) Units that are located in a noncontinental area and that combust coal or oil shall not discharge any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

§ 60.43b Standard for particulate matter.

Intentionally omitted.

§ 60.44b Standard for nitrogen oxides.

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas 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 following emission limits:

Fuel/Steam generating unit type	Nitrogen oxide emission limits ng/J (lb/million Btu) (expressed as NO_2) heat input
(1) Natural gas and distillate oil, except (4):	
(i) Low heat release rate............................	43 (0.10)
(ii) High heat release rate...........................	86 (0.20)
(2) Intentionally omitted.	
(3) Intentionally omitted.	
(4) Intentionally omitted.	

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of a limit determined by the use of the following formula:

$$E_n=[(EL_{go}\ H_{go})+(EL_{ro}\ H_{ro})+(EL_c\ H_c)]/(H_{go}+H_{ro}+H_c)$$

where:

E_n = NO_X emission limit (expressed as NO_2), ng/J (lb/MMBtu)

EL_{go} = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu)

H_{go} = Heat input from combustion of natural gas or distillate oil, J (MMBtu);

EL_{ro} = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);

H_{ro} = Heat input from combustion of residual oil, J (MMBtu)

EL_c = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c = Heat input from combustion of coal, J (MMBtu).

(c) Intentionally omitted.

(d) Intentionally omitted.

(e) Intentionally omitted.

(f) Intentionally omitted.

(g) Intentionally omitted.

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

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

(j) Intentionally omitted.

(k) Intentionally omitted.

(l) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction or reconstruction after July 9, 1997 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 following limits:

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

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input from the combustion of all fuels, a limit determined by use of the following formula:

$E_n = [(0.10 * H_{go}) + (0.20 * H_r)]/(H_{go} + H_r)$

Where:

E_n = NO_X emission limit, (lb/MMBtu),

H_{go} = 30-day heat input from combustion of natural gas or distillate oil, and

H_r = 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i) of subpart Da of this part and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of this part.

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO_2 emission standards under §60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil and complying with the fuel based limit under § 60.42b(d) or § 60.42b(k)(2) are allowed to exceed the limit 30 operating days per calendar year for by-product plant maintenance.

(b) In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling)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. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO_2 emission rate (% Ps) and the SO_2 emission rate (Es) pursuant to §60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over the first 30 consecutive operating days of the steam generating unit. Compliance with the SO_2 standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 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.

(2) Intentionally omitted.

(3) Intentionally omitted.

(4) Intentionally omitted.

(5) Intentionally omitted.

(d) Intentionally omitted.

(e) Intentionally omitted.

(f) For the initial performance test required under §60.8, compliance with the SO_2 emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for SO_2 for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for 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 steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 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. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under §60.8, compliance with the SO_2 emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for SO_2 for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for SO_2 are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating % P_s and E_{ho} under paragraph (c), of this section whether or not the minimum emissions data requirements under §60.46b are achieved. All valid emissions data, including valid SO_2 emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating % P_s and E_{ho} pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the SO_2 control systems when oil is combusted as provided under §60.42b(i), emission data are not used to calculate % Ps or Es under §60.42b (a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under §60.42b(i).

(j) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance under §§60.42b(d)(4), 60.42b(j), and 60.42b(k)(2) shall follow the applicable procedures under § 60.49b(r).

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

(a) The PM emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_X emission standards under §60.44b apply at all times.

(b) Intentionally omitted.

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

(d) Intentionally omitted.

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

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

(2) Intentionally omitted.

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hour) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_X standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(4) Intentionally omitted.

(5) Intentionally omitted.

(f) Intentionally omitted.

(g) Intentionally omitted.

(h) Intentionally omitted.

(i) Intentionally omitted.

(j) Intentionally omitted.

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b), (f), and (h) of this section, the owner or operator of an affected facility subject to the SO_2 standards under § 60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO_2 and either O_2 or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2 control device. If the owner or operator has installed and certified SO_2 and O_2 or CO_2 CEMS according to the requirements of § 75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of § 75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously; and

(2) 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

(3) The reporting requirements of § 60.49b are met. SO_2 and CO_2 (or O_2) data used to meet

the requirements of § 60.49b 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_2 data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate, or

(2) Measuring SO_2 according to Method 6B of appendix A of this part at the inlet or outlet to the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily SO_2 emission rate, ED, shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A-8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19-20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO_2 emission rates measured by the CEMS required by paragraph (a) of this section and required under § 60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under §60.42(b). Each 1-hour average SO_2 emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to § 60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

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

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO_2 CEMS at the inlet to the SO_2 control device is 125 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2 control device is 50 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted. Alternatively, SO_2 span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required CO_2 and O_2 monitors and for SO_2 and NO_X monitors with span values less than 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to 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_X span values less than 100 ppm;

(ii) For all required CO_2 and O_2 monitors and for SO_2 and NO_X monitors 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_X span values less than or equal to 30 ppm; and

(iii) For SO_2, CO_2, and O_2 monitoring systems and for NO_X emission rate monitoring systems, 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_2 emission level during the RATA), and for NO_X when the average NO_X emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under § 60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in § 60.49b(r).

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

(a) Intentionally omitted.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_X standard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate a CEMS for measuring NO_X and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_X emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49b. Data reported to meet the requirements of §60.49b 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.

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

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

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

(1) Intentionally omitted.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_X is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_X span values shall be determined as follows:

Fuel	Span values for nitrogen oxides (PPM)
Natural gas..	500
Oil...	500
Coal..	1,000
Mixtures..	500(x+y)+1,000z

where:

x = Fraction of total heat input derived from natural gas,

y = Fraction of total heat input derived from oil, and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

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

(g) Intentionally omitted.

(h) Intentionally omitted.

(i) Intentionally omitted.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), or (5) of this section is not required to install or operate a COMS for measuring opacity if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2 or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under Sec. 60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO_2 or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

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

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

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

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

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

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

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the appropriate delegated permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) Intentionally omitted.

§ 60.49b Reporting and recordkeeping requirements.

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

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

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i),

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired, and,

(4) Notification that an emerging technology will be used for controlling emissions of SO_2. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2, PM, and/or NO_X emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

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

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_X emission rates (i.e., ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (i.e., the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e., flue gas O_2 level);

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

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

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

(e) Intentionally omitted.

(f) Intentionally omitted.

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

(1) Calendar date;

(2) The average hourly NO_X emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted.

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

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

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

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

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

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

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

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

(1) Intentionally omitted.

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

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

(ii) Intentionally omitted.

(3) Intentionally omitted.

(4) Intentionally omitted.

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

(j) Intentionally omitted.

(k) Intentionally omitted.

(l) Intentionally omitted.

(m) Intentionally omitted.

(n) Intentionally omitted.

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

(p) Intentionally omitted.

(q) Intentionally omitted.

(r) Intentionally omitted.

(s) Intentionally omitted.

(t) Intentionally omitted.

(u) Intentionally omitted.

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

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

(x) Intentionally omitted.

SECTION G.3 New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Coal receiving and handling system, to be permitted in 2010, except the truck or railcar receiving and unloading station permitted in 2008, using enclosed conveyors consisting of the following equipment:

(A) 1200 ton per hour enclosed coal conveyor with particulate emissions from drop point to active coal pile stacking tube controlled by an insertable dust filter, exhausting to Stack S-1D.

(B) One (1) 1200 ton per hour truck or railcar receiving and unloading station with enclosed drop points and particulate emissions controlled by a baghouse and exhausting to Stack S-1B.

(C) One (1) 1,800 ton per hour reclaim tunnel using two (2) 900 ton per hour conveyors with enclosed drop points and particulate matter controlled by a baghouse and exhausting to Stack S-2A.

(D) Two (2) 900 ton per hour enclosed coal conveyors with particulate matter from enclosed drop points controlled by insertable dust filters and exhausting to Stacks S-2B and S-2C.

(E) Two (2) enclosed coal bunkers with a total loading capacity of 1800 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-3A and S-3B.

Under the NSPS for Coal Preparation Plants (40 CFR 60, Subpart Y), these emission units are considered to be affected facilities in a coal preparation plant that will commence construction after October 24, 1974.

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

G.3.1 General Provisions Relating to NSPS Subpart Y [326 IAC 12-1] [40 CFR 60, Subpart A]

The provisions of 40 CFR 60 Subpart A - General Provisions, which are incorporated as 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR 60 Subpart Y.

G.3.2 NSPS for Coal Preparation Plants [40 CFR 60, Subpart Y]

Pursuant to 40 CFR 60, Subpart Y, the Permittee shall comply with the provisions of 40 CFR 60, Subpart Y, upon startup of the affected units, as follows:

§ 60.250 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to any of the following affected facilities in coal preparation plants which process more than 181 Mg (200 tons) per day: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 24, 1974, is subject to the requirements of this subpart.

§ 60.251 Definitions.

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

(a) *Coal preparation plant* means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

(b) *Bituminous coal* means solid fossil fuel classified as bituminous coal by ASTM Designation D388–77, 90, 91, 95, or 98a (incorporated by reference—see §60.17).

(c) *Coal* means all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM Designation D388–77, 90, 91, 95, or 98a (incorporated by reference—see §60.17).

(d) *Cyclonic flow* means a spiraling movement of exhaust gases within a duct or stack.

(e) *Thermal dryer* means any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

(f) *Pneumatic coal-cleaning equipment* means any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(g) *Coal processing and conveying equipment* means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts.

(h) *Coal storage system* means any facility used to store coal except for open storage piles.

(i) *Transfer and loading system* means any facility used to transfer and load coal for shipment.

§ 60.252 Standards for particulate matter.

(a) Intentionally omitted.

(b) Intentionally omitted.

(c) On and after the date on which the performance test required to be conducted by §60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

§ 60.253 Monitoring of operations.

Intentionally omitted.

§ 60.254 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the particular matter standards in §60.252 as follows:

(1) Method 5 shall be used to determine the particulate matter concentration. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin.

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

SECTION G.4 New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

(1) Lime and soda ash handling system, to be permitted in 2010:

(A) Transfer of lime from truck or railcar by a closed pneumatic conveyor to two (2) lime storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4A and S-4B.

(B) Transfer of soda ash from truck or railcar by a closed pneumatic conveyor to two (2) soda ash storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4C and S- 4D.

Under the NSPS for Nonmetallic Mineral Processing Plants (40 CFR 60, Subpart OOO), this emission unit is considered to be a fixed nonmetallic mineral processing plant containing conveyers, grinding mills and storage for which construction commenced after August 31, 1983.

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

G.4.1 General Provisions Relating to NSPS Subpart OOO [326 IAC 12-1] [40 CFR 60, Subpart A]

The provisions of 40 CFR 60 Subpart A - General Provisions, which are incorporated as 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR 60 Subpart OOO.

G.4.2 NSPS for Stationary Compression Ignition Internal Combustion Engines [40 CFR Part 60, Subpart OOO]

Pursuant to 40 CFR Part 60, Subpart OOO, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart OOO, upon startup of the affected units, as follows:

§ 60.670 Applicability and designation of affected facility.

(a)(1) Except as provided in paragraphs (a)(2), (b), (c), and (d) of this section, the provisions of this subpart are applicable to the following affected facilities in fixed or portable nonmetallic mineral processing plants: each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station. Also, crushers and grinding mills at hot mix asphalt facilities that reduce the size of nonmetallic minerals embedded in recycled asphalt pavement and subsequent affected facilities up to, but not including, the first storage silo or bin are subject to the provisions of this subpart.

(2) The provisions of this subpart do not apply to the following operations: All facilities located in underground mines; and stand-alone screening operations at plants without crushers or grinding mills.

(b) Intentionally omitted.

(c) Intentionally omitted.

(d)(1) When an existing facility is replaced by a piece of equipment of equal or smaller size, as defined in §60.671, having the same function as the existing facility, the new facility is exempt from the provisions of §§60.672, 60.674, and 60.675 except as provided for in paragraph (d)(3) of this section.

(2) An owner or operator complying with paragraph (d)(1) of this section shall submit the information required in §60.676(a).

(3) An owner or operator replacing all existing facilities in a production line with new facilities does not qualify for the exemption described in paragraph (d)(1) of this section and must comply with the provisions of §§60.672, 60.674 and 60.675.

(e) An affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after August 31, 1983 is subject to the requirements of this part.

(f) Table 1 of this subpart specifies the provisions of subpart A of this part 60 that apply and those that do not apply to owners and operators of affected facilities subject to this subpart.

Table 1—Applicability of Subpart A to Subpart OOO

Subpart A reference	Applies to Subpart OOO	Comment
60.1, Applicability	Yes	
60.2, Definitions	Yes	
60.3, Units and abbreviations	Yes	
60.4, Address:		
(a)	Yes	
(b)	Yes	
60.5, Determination of construction or modification	Yes	
60.6, Review of plans	Yes	
60.7, Notification and recordkeeping	Yes	Except in (a)(2) report of anticipated date of initial startup is not required (§60.676(h)).
60.8, Performance tests	Yes	Except in (d), after 30 days notice for an initially scheduled performance test, any rescheduled performance test requires 7 days notice, not 30 days (§60.675(g)).
60.9, Availability of information	Yes	
60.10, State authority	Yes	
60.11, Compliance with standards and maintenance requirements	Yes	Except in (b) under certain conditions (§§60.675 (c)(3) and (c)(4)), Method 9 observation may be reduced from 3 hours to 1 hour. Some affected facilities exempted from Method 9 tests (§60.675(h)).
60.12, Circumvention	Yes	

Subpart A reference	Applies to Subpart OOO	Comment
60.13, Monitoring requirements	Yes	
60.14, Modification	Yes	
60.15, Reconstruction	Yes	
60.16, Priority list	Yes	
60.17, Incorporations by reference	Yes	
60.18, General control device	No	Flares will not be used to comply with the emission limits.
60.19, General notification and reporting requirements	Yes	

§ 60.671 Definitions.

All terms used in this subpart, but not specifically defined in this section, shall have the meaning given them in the Act and in subpart A of this part.

Bagging operation means the mechanical process by which bags are filled with nonmetallic minerals.

Belt conveyor means a conveying device that transports material from one location to another by means of an endless belt that is carried on a series of idlers and routed around a pulley at each end.

Bucket elevator means a conveying device of nonmetallic minerals consisting of a head and foot assembly which supports and drives an endless single or double strand chain or belt to which buckets are attached.

Building means any frame structure with a roof.

Capacity means the cumulative rated capacity of all initial crushers that are part of the plant.

Capture system means the equipment (including enclosures, hoods, ducts, fans, dampers, etc.) used to capture and transport particulate matter generated by one or more process operations to a control device.

Control device means the air pollution control equipment used to reduce particulate matter emissions released to the atmosphere from one or more process operations at a nonmetallic mineral processing plant.

Conveying system means a device for transporting materials from one piece of equipment or location to another location within a plant. Conveying systems include but are not limited to the following: Feeders, belt conveyors, bucket elevators and pneumatic systems.

Crusher means a machine used to crush any nonmetallic minerals, and includes, but is not limited to, the following types: jaw, gyratory, cone, roll, rod mill, hammermill, and impactor.

Enclosed truck or railcar loading station means that portion of a nonmetallic mineral processing plant where nonmetallic minerals are loaded by an enclosed conveying system into enclosed trucks or railcars.

Fixed plant means any nonmetallic mineral processing plant at which the processing equipment specified in §60.670(a) is attached by a cable, chain, turnbuckle, bolt or other means (except electrical connections) to any anchor, slab, or structure including bedrock.

Fugitive emission means particulate matter that is not collected by a capture system and is released to the atmosphere at the point of generation.

Grinding mill means a machine used for the wet or dry fine crushing of any nonmetallic mineral. Grinding mills include, but are not limited to, the following types: hammer, roller, rod, pebble and ball, and fluid energy. The grinding mill includes the air conveying system, air separator, or air classifier, where such systems are used.

Initial crusher means any crusher into which nonmetallic minerals can be fed without prior crushing in the plant.

Nonmetallic mineral means any of the following minerals or any mixture of which the majority is any of the following minerals:

(a) Crushed and Broken Stone, including Limestone, Dolomite, Granite, Traprock, Sandstone, Quartz, Quartzite, Marl, Marble, Slate, Shale, Oil Shale, and Shell.

(b) Sand and Gravel.

(c) Clay including Kaolin, Fireclay, Bentonite, Fuller's Earth, Ball Clay, and Common Clay.

(d) Rock Salt.

(e) Gypsum.

(f) Sodium Compounds, including Sodium Carbonate, Sodium Chloride, and Sodium Sulfate.

(g) Pumice.

(h) Gilsonite.

(i) Talc and Pyrophyllite.

(j) Boron, including Borax, Kernite, and Colemanite.

(k) Barite.

(l) Fluorospar.

(m) Feldspar.

(n) Diatomite.

(o) Perlite.

(p) Vermiculite.

(q) Mica.

(r) Kyanite, including Andalusite, Sillimanite, Topaz, and Dumortierite.

Nonmetallic mineral processing plant means any combination of equipment that is used to crush or grind any nonmetallic mineral wherever located, including lime plants, power plants, steel mills, asphalt concrete plants, portland cement plants, or any other facility processing nonmetallic minerals except as provided in §60.670 (b) and (c).

Portable plant means any nonmetallic mineral processing plant that is mounted on any chassis or skids and may be moved by the application of a lifting or pulling force. In addition, there shall be no cable, chain, turnbuckle, bolt or other means (except electrical connections) by which any piece of equipment is attached or clamped to any anchor, slab, or structure, including bedrock that must be removed prior to the application of a lifting or pulling force for the purpose of transporting the unit.

Production line means all affected facilities (crushers, grinding mills, screening operations, bucket elevators, belt conveyors, bagging operations, storage bins, and enclosed truck and railcar loading stations) which are directly connected or are connected together by a conveying system.

Screening operation means a device for separating material according to size by passing undersize material through one or more mesh surfaces (screens) in series, and retaining oversize material on the mesh surfaces (screens).

Size means the rated capacity in tons per hour of a crusher, grinding mill, bucket elevator, bagging operation, or enclosed truck or railcar loading station; the total surface area of the top screen of a screening operation; the width of a conveyor belt; and the rated capacity in tons of a storage bin.

Stack emission means the particulate matter that is released to the atmosphere from a capture system.

Storage bin means a facility for storage (including surge bins) or nonmetallic minerals prior to further processing or loading.

Transfer point means a point in a conveying operation where the nonmetallic mineral is transferred to or from a belt conveyor except where the nonmetallic mineral is being transferred to a stockpile.

Truck dumping means the unloading of nonmetallic minerals from movable vehicles designed to transport nonmetallic minerals from one location to another. Movable vehicles include but are not limited to: trucks, front end loaders, skip hoists, and railcars.

Vent means an opening through which there is mechanically induced air flow for the purpose of exhausting from a building air carrying particulate matter emissions from one or more affected facilities.

Wet mining operation means a mining or dredging operation designed and operated to extract any nonmetallic mineral regulated under this subpart from deposits existing at or below the water table, where the nonmetallic mineral is saturated with water.

Wet screening operation means a screening operation at a nonmetallic mineral processing plant which removes unwanted material or which separates marketable fines from the product by a washing process which is designed and operated at all times such that the product is saturated with water.

§ 60.672 Standard for particulate matter.

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

(1) Contain particulate matter in excess of 0.05 g/dscm (0.022 gr/dscf); and

(2) Exhibit greater than 7 percent opacity, unless the stack emissions are discharged from an affected facility using a wet scrubbing control device. Facilities using a wet scrubber must comply with the reporting provisions of §60.676 (c), (d), and (e).

(b) On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under §60.11 of this part, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any transfer point on belt conveyors or from any other affected facility any fugitive emissions which exhibit greater than 10 percent opacity, except as provided in paragraphs (c), (d), and (e) of this section.

(c) On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under §60.11 of this part, no owner or operator shall cause to be discharged into the atmosphere from any crusher, at which a capture system is not used, fugitive emissions which exhibit greater than 15 percent opacity.

(d) Truck dumping of nonmetallic minerals into any screening operation, feed hopper, or crusher is exempt from the requirements of this section.

(e) If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in paragraphs (a), (b) and (c) of this section, or the building enclosing the affected facility or facilities must comply with the following emission limits:

(1) No owner or operator shall cause to be discharged into the atmosphere from any building enclosing any transfer point on a conveyor belt or any other affected facility any visible fugitive emissions except emissions from a vent as defined in §60.671.

(2) No owner or operator shall cause to be discharged into the atmosphere from any vent of any building enclosing any transfer point on a conveyor belt or any other affected facility emissions which exceed the stack emissions limits in paragraph (a) of this section.

(f) On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under §60.11 of this part, no owner or operator shall cause to be discharged into the atmosphere from any baghouse that controls emissions from only an individual, enclosed storage bin, stack emissions which exhibit greater than 7 percent opacity.

(g) Owners or operators of multiple storage bins with combined stack emissions shall comply with the emission limits in paragraph (a)(1) and (a)(2) of this section.

(h) On and after the sixtieth day after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup, no owner or operator shall cause to be discharged into the atmosphere any visible emissions from:

(1) Wet screening operations and subsequent screening operations, bucket elevators, and belt conveyors that process saturated material in the production line up to the next crusher, grinding mill or storage bin.

(2) Screening operations, bucket elevators, and belt conveyors in the production line downstream of wet mining operations, where such screening operations, bucket elevators, and belt conveyors process saturated materials up to the first crusher, grinding mill, or storage bin in the production line.

[51 FR 31337, Aug. 1, 1985, as amended at 62 FR 31359, June 9, 1997; 65 FR 61778, Oct. 17, 2000]

§ 60.673 Reconstruction.

(a) The cost of replacement of ore-contact surfaces on processing equipment shall not be considered in calculating either the “fixed capital cost of the new components” or the “fixed capital cost that would be required to construct a comparable new facility” under §60.15. Ore-contact surfaces are crushing surfaces; screen meshes, bars, and plates; conveyor belts; and elevator buckets.

(b) Under §60.15, the “fixed capital cost of the new components” includes the fixed capital cost of all depreciable components (except components specified in paragraph (a) of this section) which are or will be replaced pursuant to all continuous programs of component replacement commenced within any 2-year period following August 31, 1983.

§ 60.674 Monitoring of operations.

Intentionally omitted – particulate emissions controlled by wet scrubber.

§ 60.675 Test methods and procedures.

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

(b) The owner or operator shall determine compliance with the particulate matter standards in §60.672(a) as follows:

(1) Method 5 or Method 17 shall be used to determine the particulate matter concentration. The sample volume shall be at least 1.70 dscm (60 dscf). For Method 5, if the gas stream being sampled is at ambient temperature, the sampling probe and filter may be operated without heaters. If the gas stream is above ambient temperature, the sampling probe and filter may be operated at a temperature high enough, but no higher than 121 °C (250 °F), to prevent water condensation on the filter.

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

(c)(1) In determining compliance with the particulate matter standards in §60.672 (b) and (c), the owner or operator shall use Method 9 and the procedures in §60.11, with the following additions:

(i) The minimum distance between the observer and the emission source shall be 4.57 meters (15 feet).

(ii) The observer shall, when possible, select a position that minimizes interference from other fugitive emission sources (e.g., road dust). The required observer position relative to the sun (Method 9, Section 2.1) must be followed.

(iii) For affected facilities using wet dust suppression for particulate matter control, a visible mist is sometimes generated by the spray. The water mist must not be confused with particulate matter emissions and is not to be considered a visible emission. When a water mist of this nature is present, the observation of emissions is to be made at a point in the plume where the mist is no longer visible.

(2) In determining compliance with the opacity of stack emissions from any baghouse that controls emissions only from an individual enclosed storage bin under §60.672(f) of this subpart, using Method 9, the duration of the Method 9 observations shall be 1 hour (ten 6-minute averages).

(3) When determining compliance with the fugitive emissions standard for any affected facility described under §60.672(b) of this subpart, the duration of the Method 9 observations may be reduced from 3 hours (thirty 6-minute averages) to 1 hour (ten 6-minute averages) only if the following conditions apply:

(i) There are no individual readings greater than 10 percent opacity; and

(ii) There are no more than 3 readings of 10 percent for the 1-hour period.

(4) When determining compliance with the fugitive emissions standard for any crusher at which a capture system is not used as described under §60.672(c) of this subpart, the duration of the Method 9 observations may be reduced from 3 hours (thirty 6-minute averages) to 1 hour (ten 6-minute averages) only if the following conditions apply:

(i) There are no individual readings greater than 15 percent opacity; and

(ii) There are no more than 3 readings of 15 percent for the 1-hour period.

(d) In determining compliance with §60.672(e), the owner or operator shall use Method 22 to determine fugitive emissions. The performance test shall be conducted while all affected facilities inside the building are operating. The performance test for each building shall be at least 75 minutes in duration, with each side of the building and the roof being observed for at least 15 minutes.

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

(1) For the method and procedure of paragraph (c) of this section, if emissions from two or more facilities continuously interfere so that the opacity of fugitive emissions from an individual affected facility cannot be read, either of the following procedures may be used:

(i) Use for the combined emission stream the highest fugitive opacity standard applicable to any of the individual affected facilities contributing to the emissions stream.

(ii) Separate the emissions so that the opacity of emissions from each affected facility can be read.

(f) To comply with §60.676(d), the owner or operator shall record the measurements as required in §60.676(c) using the monitoring devices in §60.674 (a) and (b) during each particulate matter run and shall determine the averages.

(g) If, after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting any rescheduled performance test required in this section, the owner or operator of an affected facility shall submit a notice to the Administrator at least 7 days prior to any rescheduled performance test.

(h) Initial Method 9 performance tests under §60.11 of this part and §60.675 of this subpart are not required for:

(1) Wet screening operations and subsequent screening operations, bucket elevators, and belt conveyors that process saturated material in the production line up to, but not including the next crusher, grinding mill or storage bin.

(2) Screening operations, bucket elevators, and belt conveyors in the production line downstream of wet mining operations, that process saturated materials up to the first crusher, grinding mill, or storage bin in the production line.

[54 FR 6680, Feb. 14, 1989, as amended at 62 FR 31360, June 9, 1997]

§ 60.676 Reporting and recordkeeping.

(a) Each owner or operator seeking to comply with §60.670(d) shall submit to the Administrator the following information about the existing facility being replaced and the replacement piece of equipment.

(1) For a crusher, grinding mill, bucket elevator, bagging operation, or enclosed truck or railcar loading station:

(i) The rated capacity in megagrams or tons per hour of the existing facility being replaced and

(ii) The rated capacity in tons per hour of the replacement equipment.

(2) For a screening operation:

(i) The total surface area of the top screen of the existing screening operation being replaced and

(ii) The total surface area of the top screen of the replacement screening operation.

(3) For a conveyor belt:

(i) The width of the existing belt being replaced and

(ii) The width of the replacement conveyor belt.

(4) For a storage bin:

(i) The rated capacity in megagrams or tons of the existing storage bin being replaced and

(ii) The rated capacity in megagrams or tons of replacement storage bins.

(b) [Reserved]

(c) During the initial performance test of a wet scrubber, and daily thereafter, the owner or operator shall record the measurements of both the change in pressure of the gas stream across the scrubber and the scrubbing liquid flow rate.

(d) After the initial performance test of a wet scrubber, the owner or operator shall submit semiannual reports to the Administrator of occurrences when the measurements of the scrubber pressure loss (or gain) and liquid flow rate differ by more than ±30 percent from the averaged determined during the most recent performance test.

(e) The reports required under paragraph (d) shall be postmarked within 30 days following end of the second and fourth calendar quarters.

(f) The owner or operator of any affected facility shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in §60.672 of this subpart, including reports of opacity observations made using Method 9 to demonstrate compliance with §60.672(b), (c), and (f), and reports of observations using Method 22 to demonstrate compliance with §60.672(e).

(g) The owner or operator of any screening operation, bucket elevator, or belt conveyor that processes saturated material and is subject to §60.672(h) and subsequently processes unsaturated materials, shall submit a report of this change within 30 days following such change. This screening operation, bucket elevator, or belt conveyor is then subject to the 10 percent opacity limit in §60.672(b) and the emission test requirements of §60.11 and this subpart. Likewise a screening operation, bucket elevator, or belt conveyor that processes unsaturated material but subsequently processes saturated material shall submit a report of this change within 30 days following such change. This screening operation, bucket elevator, or belt conveyor is then subject to the no visible emission limit in §60.672(h).

(h) The subpart A requirement under §60.7(a)(2) for notification of the anticipated date of initial startup of an affected facility shall be waived for owners or operators of affected facilities regulated under this subpart.

(i) A notification of the actual date of initial startup of each affected facility shall be submitted to the Administrator.

(1) For a combination of affected facilities in a production line that begin actual initial startup on the same day, a single notification of startup may be submitted by the owner or operator to the Administrator. The notification shall be postmarked within 15 days after such date and shall include a description of each affected facility, equipment manufacturer, and serial number of the equipment, if available.

(2) For portable aggregate processing plants, the notification of the actual date of initial startup shall include both the home office and the current address or location of the portable plant.

(j) The requirements of this section remain in force until and unless the Agency, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such States. In that event, affected facilities within the State will be relieved of the obligation to comply with the reporting requirements of this section, provided that they comply with requirements established by the State.

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

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

The power block includes the following, among other emission units:

(1) Two (2) combined cycle combustion turbine trains each consisting of a combustion turbine and a heat recovery steam generator, designated as CTHRSG1 and CTHRSG2, permitted in 2008, using diffusion combustors firing either syngas, natural gas, or combined syngas and natural gas, and exhausting to Stacks S-2a and S-2b. The turbine trains use nitrogen diluent injection (to control NO_X) when firing syngas, steam injection when firing natural gas, and nitrogen diluent injection and steam injection when co-firing syngas and natural gas.

Nominal Heat Input Capacity (HHV) for each Combustion Turbine Train	
Fuel	**MMBtu/Hr**
Syngas Only	2106
Natural Gas Only	2109
Combined Syngas and Natural Gas	2129

Stacks S-2a and S-2b have continuous emissions monitors (CEMs) for carbon monoxide (CO), nitrogen oxides (NO_X) and sulfur dioxide (SO_2). Mercury (Hg) will be monitored per requirements of 40 CFR Part 60, Subpart Da.

Under the NSPS for Coal-Fired Electric Steam Generating Units – Hg Budget Trading Program (40 CFR 60, Subpart HHHH), this emission unit contains coal-derived fuel-fired combustion units.

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

G.5.1 General Provisions Relating to NSPS Subpart HHHH [326 IAC 12-1] [40 CFR 60, Subpart A]

The provisions of 40 CFR 60 Subpart A - General Provisions, which are incorporated as 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR 60 Subpart HHHH.

G.5.2 NSPS for Stationary Compression Ignition Internal Combustion Engines [40 CFR Part 60, Subpart HHHH]

Pursuant to 40 CFR Part 60, Subpart IIII, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart HHHH, upon startup of the affected units, as follows:

§ 60.4101 Purpose.

This subpart establishes the model rule comprising general provisions and the designated representative, permitting, allowance, and monitoring provisions for the State mercury (Hg) Budget Trading Program, under section 111 of the Clean Air Act (CAA) and §60.24(h)(6), as a means of reducing national Hg emissions. The owner or operator of a unit or a source shall comply with the requirements of this subpart as a matter of Federal law only if the State with jurisdiction over the unit and the source incorporates by reference this subpart or otherwise adopts the requirements of this subpart in accordance with §60.24(h)(6), the State submits to the Administrator one or more revisions of the State plan that include such adoption, and the Administrator approves such revisions. If the State adopts the requirements of this subpart in accordance with §60.24(h)(6), then the State authorizes the Administrator to assist the State in implementing the Hg Budget Trading Program by carrying out the functions set forth for the Administrator in this subpart.

§ 60.4102 Definitions.

Link to an amendment published at 72 FR 59205, Oct. 19, 2007.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Account number means the identification number given by the Administrator to each Hg Allowance Tracking System account.

Acid rain emissions limitation means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Allocate or *allocation* means the determination by the permitting authority or the Administrator of the amount of Hg allowances to be initially credited to a Hg Budget unit or a new unit set-aside under §§60.4140 through 60.4142.

Allowance transfer deadline means, for a control period, midnight of March 1, if it is a business day, or, if March 1 is not a business day, midnight of the first business day thereafter immediately following the control period and is the deadline by which a Hg allowance transfer must be submitted for recordation in a Hg Budget source's compliance account in order to be used to meet the source's Hg Budget emissions limitation for such control period in accordance with §60.4154.

Alternate Hg designated representative means, for a Hg Budget source and each Hg Budget unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source in accordance with §§60.4110 through 60.4114, to act on behalf of the Hg designated representative in matters pertaining to the Hg Budget Trading Program.

Automated data acquisition and handling system or *DAHS* means that component of the continuous emission monitoring system (CEMS), or other emissions monitoring system approved for use under §§60.4170 though 60.4176, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required §§60.4170 through 60.4176.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other nonmerchantable material and that is:

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil-or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

CAIR NO X *Annual Trading Program* means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AA through II of part 96 of this chapter and §51.123 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

CAIR NO X *Ozone Season Trading Program* means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAAA through IIII of part 96 of this chapter and §51.123 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

CAIR SO 2 *Trading Program* means a multi-state sulfur dioxide air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAA through III of part 96 of this chapter and §51.124 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

Clean Air Act or *CAA* means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004)andepsiv;[1] (incorporated by reference, see §60.17).

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year.

Cogeneration unit means a stationary, coal-fired boiler or stationary, coal-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

Commence commercial operation means, with regard to a unit serving a generator:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in §60.4105.

(i) For a unit that is a Hg Budget unit under §60.4104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit that is a Hg Budget unit under §60.4104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.* , repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in §60.4105, for a unit that is not a Hg Budget unit under §60.4104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a Hg Budget unit under §60.4104.

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.* , repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Commence operation means:

(1) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber, except as provided in §60.4105.

(i) For a unit that is a Hg Budget unit under §60.4104 on the date the unit commences operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit that is a Hg Budget unit under §60.4104 on the date the unit commences operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.* , repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in §60.4105, for a unit that is not a Hg Budget unit under §60.4104 on the date the unit commences operation as defined in paragraph (1) of this definition, the unit's date for commencement of operation shall be the date on which the unit becomes a Hg Budget unit under §60.4104.

(i) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.* , repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1) or (2) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means a Hg Allowance Tracking System account, established by the Administrator for a Hg Budget source under §§60.4150 through 60.4157, in which any Hg allowance allocations for the Hg Budget units at the source are initially recorded and in which are held any Hg allowances available for use for a control period in order to meet the source's Hg Budget emissions limitation in accordance with §60.4154.

Continuous emission monitoring system or *CEMS* means the equipment required under §§60.4170 through 60.4176 to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of Hg emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with part 75 of this chapter. The following systems are the principal types of CEMS required under §§60.4170 through 60.4176:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in units of standard cubic feet per hour (scfh);

(2) A Hg concentration monitoring system, consisting of a Hg pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of Hg emissions in units of micrograms per dry standard cubic meter (μgm/dscm);

(3) A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O.

(4) A carbon dioxide monitoring system, consisting of a CO_2 concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(5) An oxygen monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period beginning January 1 of a calendar year and ending on December 31 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the Hg designated representative and as determined by the Administrator in accordance with §§60.4170 through 60.4176.

Excess emissions means any ounce of mercury emitted by the Hg Budget units at a Hg Budget source during a control period that exceeds the Hg Budget emissions limitation for the source.

General account means a Hg Allowance Tracking System account, established under §60.4151, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a cogeneration unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a specified period of time, the product (in MMBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/MMBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the Hg designated representative and determined by the Administrator in accordance with §§60.4170 through 60.4176 and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in MMBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in MMBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Hg allowance means a limited authorization issued by the permitting authority or the Administrator under §§60.4140 through 60.4142 to emit one ounce of mercury during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the Hg Budget Trading Program. An authorization to emit mercury that is not issued under the provisions of a State plan that adopt the requirements of this subpart and are approved by the Administrator in accordance with §60.24(h)(6) shall not be a “Hg allowance.”

Hg allowance deduction or *deduct Hg allowances* means the permanent withdrawal of Hg allowances by the Administrator from a compliance account in order to account for a specified number of ounces of total mercury emissions from all Hg Budget units at a Hg Budget source for a control period, determined in accordance with §§60.4150 though 60.4157 and §§60.4170 through 60.4176, or to account for excess emissions.

Hg allowances held or *hold Hg allowances* means the Hg allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with §§60.4150 through 60.4162, in a Hg Allowance Tracking System account.

Hg Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of Hg allowances under the Hg Budget Trading Program. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

Hg Allowance Tracking System account means an account in the Hg Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of Hg allowances.

Hg authorized account representative means, with regard to a general account, a responsible natural person who is authorized, in accordance with §60.4152, to transfer and otherwise dispose of Hg allowances held in the general account and, with regard to a compliance account, the Hg designated representative of the source.

Hg Budget emissions limitation means, for a Hg Budget source, the equivalent in ounces of the Hg allowances available for deduction for the source under §60.4154(a) and (b) for a control period.

Hg Budget permit means the legally binding and Federally enforceable written document, or portion of such document, issued by the permitting authority under §§60.4120 through 60.4124, including any permit revisions, specifying the Hg Budget Trading Program requirements applicable to a Hg Budget source, to each Hg Budget unit at the source, and to the owners and operators and the Hg designated representative of the source and each such unit.

Hg Budget source means a source that includes one or more Hg Budget units.

Hg Budget Trading Program means a multi-state Hg air pollution control and emission reduction program approved and administered by the Administrator in accordance with this subpart and §60.24(h)(6), as a means of reducing national Hg emissions.

Hg Budget unit means a unit that is subject to the Hg Budget Trading Program under §60.4104.

Hg designated representative means, for a Hg Budget source and each Hg Budget unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with §§60.4110 through 60.4114, to represent and legally bind each owner and operator in matters pertaining to the Hg Budget Trading Program.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

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

Maximum design heat input means, starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady-state basis as specified by the manufacturer of the unit, or, starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady-state basis, such decreased maximum amount as specified by the person conducting the physical change.

Monitoring system means any monitoring system that meets the requirements of §§60.4170 through 60.4176, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as specified by the person conducting the physical change.

Operator means any person who operates, controls, or supervises a Hg Budget unit or a Hg Budget source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Ounce means 2.84×10^7 micrograms. For the purpose of determining compliance with the Hg Budget emissions limitation, total ounces of mercury emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with §§60.4170 through 60.4176, but with any remaining fraction of an ounce equal to or greater than 0.50 ounces deemed to equal one ounce and any remaining fraction of an ounce less than 0.50 ounces deemed to equal zero ounces.

Owner means any of the following persons:

(1) With regard to a Hg Budget source or a Hg Budget unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a Hg Budget unit at the source or the Hg Budget unit;

(ii) Any holder of a leasehold interest in a Hg Budget unit at the source or the Hg Budget unit; or

(iii) Any purchaser of power from a Hg Budget unit at the source or the Hg Budget unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such Hg Budget unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the Hg allowances held in the general account and who is subject to the binding agreement for the Hg authorized account representative to represent the person's ownership interest with respect to Hg allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the Hg Budget Trading Program in accordance with §§60.4120 through 60.4124 or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to Hg allowances, the movement of Hg allowances by the Administrator into or between Hg Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;

(2) Integrated gasification combined cycle;

(3) Magnetohydrodynamics;

(4) Direct and indirect coal-fired turbines;

(5) Integrated gasification fuel cells; or

(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Serial number means, for a Hg allowance, the unique identification number assigned to each Hg allowance by the Administrator.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the CAA, a “source,” including a “source” with multiple units, shall be considered a single “facility.”

State means:

(1) For purposes of referring to a governing entity, one of the States in the United States, the District of Columbia, or, if approved for treatment as a State under part 49 of this chapter, the Navajo Nation or Ute Indian Tribe that adopts the Hg Budget Trading Program pursuant to §60.24(h)(6); or

(2) For purposes of referring to geographic areas, one of the States in the United States, the District of Columbia, the Navajo Nation Indian country, or the Ute Tribe Indian country.

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

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery. Compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the CAA and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the CAA and part 70 or 71 of this chapter.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV - 10.55(W + 9H)$$

Where:

LHV = lower heating value of fuel in Btu/lb,

HHV = higher heating value of fuel in Btu/lb,

W = Weight % of moisture in fuel, and

H = Weight % of hydrogen in fuel

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary coal-fired boiler or a stationary coal-fired combustion turbine.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or *hour of unit operation* means an hour in which a unit combusts any fuel.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heat application (*e.g.* , space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.* , thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 60.4103 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu—British thermal unit.

CO_2—carbon dioxide.

H_2O—water.

Hg—mercury.

hr—hour.

kW—kilowatt electrical.

kWh—kilowatt hour.

lb—pound.

MMBtu—million Btu.

MWe—megawatt electrical.

MWh—megawatt hour.

NO_X—nitrogen oxides.

O_2—oxygen.

ppm—parts per million.

scfh—standard cubic feet per hour.

SO_2—sulfur dioxide.

yr—year.

§ 60.4104 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be Hg Budget units, and any source that includes one or more such units shall be a Hg Budget source, subject to the requirements of this subpart and subparts BB through HH of this part: Any stationary, coal-fired boiler or stationary, coal-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a Hg Budget unit begins to combust coal or coal-derived fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a Hg Budget unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts coal or coal-derived fuel and serves such generator.

(b) The units in a State that meet the requirements set forth in paragraphs (b)(1)(i) or (b)(2) of this section shall not be Hg Budget units:

(1)(i) Any unit that is a Hg Budget unit under paragraph (a)(1) or (2) of this section:

(A) Qualifying as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraph (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets all such requirements, the unit shall become an Hg Budget unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(2) Any unit that is an Hg Budget unit under paragraph (a)(1) or (2) of this section, is a solid waste incineration unit combusting municipal waste, and is subject to the requirements of:

(i) A State Plan approved by the Administrator in accordance with subpart Cb of part 60 of this chapter (emissions guidelines and compliance times for certain large municipal waste combustors);

(ii) Subpart Eb of part 60 of this chapter (standards of performance for certain large municipal waste combustors);

(iii) Subpart AAAA of part 60 of this chapter (standards of performance for certain small municipal waste combustors);

(iv) A State Plan approved by the Administrator in accordance with subpart BBBB of part 60 of this chapter (emission guidelines and compliance times for certain small municipal waste combustion units);

(v) Subpart FFF, of part 62 of this chapter (Federal Plan requirements for certain large municipal waste combustors); or

(vi) Subpart JJJ of part 62 of this chapter (Federal Plan requirements for certain small municipal waste combustion units).

[71 FR 33400, June 9, 2006]

§ 60.4105 Retired unit exemption.

(a)(1) Any Hg Budget unit that is permanently retired shall be exempt from the Hg Budget Trading Program, except for the provisions of this section, §60.4102, §60.4103, §60.4104, §60.4106(c)(4) through (8), §60.4107, and §§60.4150 through 60.4162.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the Hg Budget unit is permanently retired. Within 30 days of the unit's permanent retirement, the Hg designated representative shall submit a statement to the permitting authority otherwise responsible for administering any Hg Budget permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

(3) After receipt of the statement under paragraph (a)(2) of this section, the permitting authority will amend any permit under §§60.4120 through 60.4124 covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (a)(1) and (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any mercury, starting on the date that the exemption takes effect.

(2) The permitting authority will allocate Hg allowances under §§60.4140 through 60.4142 to a unit exempt under paragraph (a) of this section.

(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(4) The owners and operators and, to the extent applicable, the Hg designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the Hg Budget Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(5) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the Hg designated representative of the source submits a complete Hg Budget permit application under §60.4122 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2010 or the date on which the unit resumes operation.

(6) On the earlier of the following dates, a unit exempt under paragraph (a) of this section shall lose its exemption:

(i) The date on which the Hg designated representative submits a Hg Budget permit application for the unit under paragraph (b)(5) of this section;

(ii) The date on which the Hg designated representative is required under paragraph (b)(5) of this section to submit a Hg Budget permit application for the unit; or

(iii) The date on which the unit resumes operation, if the Hg designated representative is not required to submit a Hg Budget permit application for the unit.

(7) For the purpose of applying monitoring, reporting, and recordkeeping requirements under §§60.4170 through 60.4176, a unit that loses its exemption under paragraph (a) of this section shall be treated as a unit that commences operation and commercial operation on the first date on which the unit resumes operation.

§ 60.4106 Standard requirements.

(a) *Permit Requirements.* (1) The Hg designated representative of each Hg Budget source required to have a title V operating permit and each Hg Budget unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete Hg Budget permit application under §60.4122 in accordance with the deadlines specified in §60.4121(a) and (b); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a Hg Budget permit application and issue or deny a Hg Budget permit.

(2) The owners and operators of each Hg Budget source required to have a title V operating permit and each Hg Budget unit required to have a title V operating permit at the source shall have a Hg Budget permit issued by the permitting authority under §§60.4120 through 60.4124 for the source and operate the source and the unit in compliance with such Hg Budget permit.

(3) The owners and operators of a Hg Budget source that is not required to have a title V operating permit and each Hg Budget unit that is not required to have a title V operating permit are not required to submit a Hg Budget permit application, and to have a Hg Budget permit, under §§60.4120 through 60.4124 for such Hg Budget source and such Hg Budget unit.

(b) *Monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the Hg designated representative, of each Hg Budget source and each Hg Budget unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§60.4170 through 60.4176.

(2) The emissions measurements recorded and reported in accordance with §§60.4170 through 60.4176 shall be used to determine compliance by each Hg Budget source with the Hg Budget emissions limitation under paragraph (c) of this section.

(c) *Mercury emission requirements.* (1) As of the allowance transfer deadline for a control period, the owners and operators of each Hg Budget source and each Hg Budget unit at the source shall hold, in the source's compliance account, Hg allowances available for compliance deductions for the control period under §60.4154(a) in an amount not less than the ounces of total mercury emissions for the control period from all Hg Budget units at the source, as determined in accordance with §§60.4170 through 60.4176.

(2) A Hg Budget unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under §60.4170(b)(1) or (2).

(3) A Hg allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the Hg allowance was allocated.

(4) Hg allowances shall be held in, deducted from, or transferred into or among Hg Allowance Tracking System accounts in accordance with §§60.4160 through 60.4162.

(5) A Hg allowance is a limited authorization to emit one ounce of mercury in accordance with the Hg Budget Trading Program. No provision of the Hg Budget Trading Program, the Hg Budget permit application, the Hg Budget permit, or an exemption under §60.4105 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A Hg allowance does not constitute a property right.

(7) Upon recordation by the Administrator under §§60.4150 through 60.4162, every allocation, transfer, or deduction of a Hg allowance to or from a Hg Budget unit's compliance account is incorporated automatically in any Hg Budget permit of the source that includes the Hg Budget unit.

(d) *Excess emissions requirements.* (1) If a Hg Budget source emits mercury during any control period in excess of the Hg Budget emissions limitation, then:

(i) The owners and operators of the source and each Hg Budget unit at the source shall surrender the Hg allowances required for deduction under §60.4154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(ii) Each ounce of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(2) [Reserved]

(e) *Recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of the Hg Budget source and each Hg Budget unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under §60.4113 for the Hg designated representative for the source and each Hg Budget unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §60.4113 changing the Hg designated representative.

(ii) All emissions monitoring information, in accordance with §§60.4170 through 60.4176, provided that to the extent that §§60.4170 through 60.4176 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Hg Budget Trading Program.

(iv) Copies of all documents used to complete a Hg Budget permit application and any other submission under the Hg Budget Trading Program or to demonstrate compliance with the requirements of the Hg Budget Trading Program.

(2) The Hg designated representative of a Hg Budget source and each Hg Budget unit at the source shall submit the reports required under the Hg Budget Trading Program, including those under §§60.4170 through 60.4176.

(f) *Liability.* (1) Each Hg Budget source and each Hg Budget unit shall meet the requirements of the Hg Budget Trading Program.

(2) Any provision of the Hg Budget Trading Program that applies to a Hg Budget source or the Hg designated representative of a Hg Budget source shall also apply to the owners and operators of such source and of the Hg Budget units at the source.

(3) Any provision of the Hg Budget Trading Program that applies to a Hg Budget unit or the Hg designated representative of a Hg Budget unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the Hg Budget Trading Program, a Hg Budget permit application, a Hg Budget permit, or an exemption under §60.4105 shall be construed as exempting or excluding the owners and operators, and the Hg designated representative, of a Hg Budget source or Hg Budget unit from compliance with any other provision of the applicable, approved State implementation plan, a Federally enforceable permit, or the CAA.

§ 60.4107 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the Hg Budget Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the Hg Budget Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the Hg Budget Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 60.4108 Appeal procedures.

The appeal procedures for decisions of the Administrator under the Hg Budget Trading Program shall be the procedures set forth in part 78 of this chapter. The terms “subpart HHHH of this part,” “§60.4141(b)(2) or (c)(2),” “§60.4154,” “§60.4156,” “§60.4161,” “§60.4175,” “Hg allowances,” “Hg Allowance Tracking System Account,” “Hg designated representative,” “Hg authorized account representative,” and “§60.4106” apply instead of the terms “subparts AA through II of part 96 of this chapter,” “§96.141(b)(2) or (c)(2),” “§96.154,” “§96.156,” “§96.161,” “§96.175,” “CAIR NO_X allowances,” “CAIR NO_X Allowance Tracking System account,” “CAIR designated representative,” “CAIR authorized account representative,” and “§96.106.”

Hg Designated Representative for Hg Budget Sources

§ 60.4110 Authorization and Responsibilities of Hg designated representative.

(a) Except as provided under §60.4111, each Hg Budget source, including all Hg Budget units at the source, shall have one and only one Hg designated representative, with regard to all matters under the Hg Budget Trading Program concerning the source or any Hg Budget unit at the source.

(b) The Hg designated representative of the Hg Budget source shall be selected by an agreement binding on the owners and operators of the source and all Hg Budget units at the source and shall act in accordance with the certification statement in §60.4113(a)(4)(iv).

(c) Upon receipt by the Administrator of a complete certificate of representation under §60.4113, the Hg designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the Hg Budget source represented and each Hg Budget unit at the source in all matters pertaining to the Hg Budget Trading Program, notwithstanding any agreement between the Hg designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the Hg designated representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No Hg Budget permit will be issued, no emissions data reports will be accepted, and no Hg Allowance Tracking System account will be established for a Hg Budget unit at a source, until the Administrator has received a complete certificate of representation under §60.4113 for a Hg designated representative of the source and the Hg Budget units at the source.

(e)(1) Each submission under the Hg Budget Trading Program shall be submitted, signed, and certified by the Hg designated representative for each Hg Budget source on behalf of which the submission is made. Each such submission shall include the following certification statement by the Hg 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.”

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a Hg Budget source or a Hg Budget unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§ 60.4111 Alternate Hg designated representative.

(a) A certificate of representation under §60.4113 may designate one and only one alternate Hg designated representative, who may act on behalf of the Hg designated representative. The agreement by which the alternate Hg designated representative is selected shall include a procedure for authorizing the alternate Hg designated representative to act in lieu of the Hg designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation under §60.4113, any representation, action, inaction, or submission by the alternate Hg designated representative shall be deemed to be a representation, action, inaction, or submission by the Hg designated representative.

(c) Except in this section and §§60.4102, 60.4110(a) and (d), 60.4112, 60.4113, 60.4151, and 60.4174, whenever the term "Hg designated representative" is used in this subpart, the term shall be construed to include the Hg designated representative or any alternate Hg designated representative.

§ 60.4112 Changing Hg designated representative and alternate Hg designated representative; changes in owners and operators.

(a) Changing Hg designated representative. The Hg designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §60.4113. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous Hg designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new Hg designated representative and the owners and operators of the Hg Budget source and the Hg Budget units at the source.

(b) Changing alternate Hg designated representative. The alternate Hg designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §60.4113. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate Hg designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate Hg designated representative and the owners and operators of the Hg Budget source and the Hg Budget units at the source.

(c) *Changes in owners and operators.* (1) In the event a new owner or operator of a Hg Budget source or a Hg Budget unit is not included in the list of owners and operators in the certificate of representation under §60.4113, such new owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the Hg designated representative and any alternate Hg designated representative of the source or unit, and the decisions and orders of the permitting authority, the Administrator, or a court, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a Hg Budget source or a Hg Budget unit, including the addition of a new owner or operator, the Hg designated representative or any alternate Hg designated representative shall submit a revision to the certificate of representation under §60.4113 amending the list of owners and operators to include the change.

§ 60.4113 Certificate of representation.

(a) A complete certificate of representation for a Hg designated representative or an alternate Hg designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the Hg Budget source, and each Hg Budget unit at the source, for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the Hg designated representative and any alternate Hg designated representative.

(3) A list of the owners and operators of the Hg Budget source and of each Hg Budget unit at the source.

(4) The following certification statements by the Hg designated representative and any alternate Hg designated representative:

(i) "I certify that I was selected as the Hg designated representative or alternate Hg designated representative, as applicable, by an agreement binding on the owners and operators of the source and each Hg Budget unit at the source."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the Hg Budget Trading Program on behalf of the owners and operators of the source and of each Hg Budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions."

(iii) "I certify that the owners and operators of the source and of each Hg Budget unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit."

(iv) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a Hg Budget unit, or where a customer purchases power from a Hg Budget unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'Hg designated representative' or 'alternate Hg designated representative,' as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each Hg Budget unit at the source; and Hg allowances and proceeds of transactions involving Hg allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of Hg allowances by contract, Hg allowances and proceeds of transactions involving Hg allowances will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the Hg designated representative and any alternate Hg designated representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 60.4114 Objections concerning Hg designated representative.

(a) Once a complete certificate of representation under §60.4113 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §60.4113 is received by the Administrator.

(b) Except as provided in §60.4112(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the Hg designated representative shall affect any representation, action, inaction, or submission of the Hg designated representative or the finality of any decision or order by the permitting authority or the Administrator under the Hg Budget Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any Hg designated representative, including private legal disputes concerning the proceeds of Hg allowance transfers.

Permits

§ 60.4120 General Hg budget trading program permit requirements.

(a) For each Hg Budget source required to have a title V operating permit, such permit shall include a Hg Budget permit administered by the permitting authority for the title V operating permit. The Hg Budget portion of the title V permit shall be administered in accordance with the permitting authority's title V operating permits regulations promulgated under part 70 or 71 of this chapter, except as provided otherwise by this section and §§60.4121 through 60.4124.

(b) Each Hg Budget permit shall contain, with regard to the Hg Budget source and the Hg Budget units at the source covered by the Hg Budget permit, all applicable Hg Budget Trading Program requirements and shall be a complete and separable portion of the title V operating permit.

§ 60.4121 Submission of Hg budget permit applications.

(a) *Duty to apply.* The Hg designated representative of any Hg Budget source required to have a title V operating permit shall submit to the permitting authority a complete Hg Budget permit application under §60.4122 for the source covering each Hg Budget unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2010 or the date on which the Hg Budget unit commences operation.

(b) *Duty to Reapply.* For a Hg Budget source required to have a title V operating permit, the Hg designated representative shall submit a complete Hg Budget permit application under §60.4122 for the source covering each Hg Budget unit at the source to renew the Hg Budget permit in accordance with the permitting authority's title V operating permits regulations addressing permit renewal.

§ 60.4122 Information requirements for Hg budget permit applications.

A complete Hg Budget permit application shall include the following elements concerning the Hg Budget source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the Hg Budget source;

(b) Identification of each Hg Budget unit at the Hg Budget source; and

(c) The standard requirements under §60.4106.

§ 60.4123 Hg budget permit contents and term.

(a) Each Hg Budget permit will contain, in a format prescribed by the permitting authority, all elements required for a complete Hg Budget permit application under §60.4122.

(b) Each Hg Budget permit is deemed to incorporate automatically the definitions of terms under §60.4102 and, upon recordation by the Administrator under §§60.4150 through 60.4162, every allocation, transfer, or deduction of a Hg allowance to or from the compliance account of the Hg Budget source covered by the permit.

(c) The term of the Hg Budget permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the Hg Budget permit with issuance, revision, or renewal of the Hg Budget source's title V operating permit.

§ 60.4124 Hg budget permit revisions.

Except as provided in §60.4123(b), the permitting authority will revise the Hg Budget permit, as necessary, in accordance with the permitting authority's title V operating permits regulations addressing permit revisions.

§ 60.4130 [Reserved]

Hg Allowance Allocations

§ 60.4140 State trading budgets.

The State trading budgets for annual allocations of Hg allowances for the control periods in 2010 through 2017 and in 2018 and thereafter are respectively as follows:

State	Annual EGU Hg budget (tons)	
	2010–2017	2018 and thereafter
Indiana	2.097	0.828

[71 FR 33401, June 9, 2006]

§ 60.4141 Timing requirements for Hg allowance allocations.

Intentionally emitted – contains requirements applicable to permitting authority.

§ 60.4142 Hg allowance allocations.

(a)(1) The baseline heat input (in MMBtu) used with respect to Hg allowance allocations under paragraph (b) of this section for each Hg Budget unit will be:

(i) For units commencing operation before January 1, 2001, the average of the three highest amounts of the unit's adjusted control period heat input for 2000 through 2004, with the adjusted control period heat input for each year calculated as the sum of the following:

(A) Any portion of the unit's control period heat input for the year that results from the unit's combustion of lignite, multiplied by 3.0;

(B) Any portion of the unit's control period heat input for the year that results from the unit's combustion of subbituminous coal, multiplied by 1.25; and

(C) Any portion of the unit's control period heat input for the year that is not covered by paragraph (a)(1)(i)(A) or (B) of this section, multiplied by 1.0.

(ii) For units commencing operation on or after January 1, 2001 and operating each calendar year during a period of 5 or more consecutive calendar years, the average of the 3 highest amounts of the unit's total converted control period heat input over the first such 5 years.

(2)(i) A unit's control period heat input for a calendar year under paragraphs (a)(1)(i) of this section, and a unit's total ounces of Hg emissions during a calendar year under paragraph (c)(3) of this section, will be determined in accordance with part 75 of this chapter, to the extent the unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the permitting authority for the unit, to the extent the unit was not otherwise subject to the requirements of part 75 of this chapter for the year. The unit's types and amounts of fuel combusted, under paragraph (a)(1)(i) of this section, will be based on the best available data reported to the permitting authority for the unit.

(ii) A unit's converted control period heat input for a calendar year specified under paragraph (a)(1)(ii) of this section equals:

(A) Except as provided in paragraph (a)(2)(ii)(B) or (C) of this section, the control period gross electrical output of the generator or generators served by the unit multiplied by 7,900 Btu/kWh and divided by 1,000,000 Btu/MMBtu, provided that if a generator is served by 2 or more units, then the gross electrical output of the generator will be attributed to each unit in proportion to the unit's share of the total control period heat input of such units for the year;

(B) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the total heat energy (in Btu) of the steam produced by the boiler during the control period, divided by 0.8 and by 1,000,000 Btu/MMBtu; or

(C) For a unit that is a combustion turbine and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the control period gross electrical output of the enclosed device comprising the compressor, combustor, and turbine multiplied by 3,413 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the control period divided by 0.8, and with the sum divided by 1,000,000 Btu/MMBtu.

(b)(1) For each control period in 2010 and thereafter, the permitting authority will allocate to all Hg Budget units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of Hg allowances equal to 95 percent for a control period in 2010 through 2014, and 97 percent for a control period in 2015 and thereafter, of the amount of ounces (*i.e.* , tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under §60.4140 (except as provided in paragraph (d) of this section).

(2) The permitting authority will allocate Hg allowances to each Hg Budget unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of Hg allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of such Hg Budget unit to the total amount of baseline heat input of all such Hg Budget units in the State and rounding to the nearest whole allowance as appropriate.

(c) For each control period in 2010 and thereafter, the permitting authority will allocate Hg allowances to Hg Budget units in the State that commenced operation on or after January 1, 2001 and do not yet have a baseline heat input (as determined under paragraph (a) of this section), in accordance with the following procedures:

(1) The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated Hg allowances equal to 5 percent for a control period in 2010 through 2014, and 3 percent for a control period in 2015 and thereafter, of the amount of ounces (*i.e.* , tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under §60.4140.

(2) The Hg designated representative of such a Hg Budget unit may submit to the permitting authority a request, in a format specified by the permitting authority, to be allocated Hg allowances, starting with the later of the control period in 2010 or the first control period after the control period in which the Hg Budget unit commences commercial operation and until the first control period for which the unit is allocated Hg allowances under paragraph (b) of this section. The Hg allowance allocation request must be submitted on or before July 1 of the first control period for which the Hg allowances are requested and after the date on which the Hg Budget unit commences commercial operation.

(3) In a Hg allowance allocation request under paragraph (c)(2) of this section, the Hg designated representative may request for a control period Hg allowances in an amount not exceeding the Hg Budget unit's total ounces of Hg emissions during the control period immediately before such control period.

(4) The permitting authority will review each Hg allowance allocation request under paragraph (c)(2) of this section and will allocate Hg allowances for each control period pursuant to such request as follows:

(i) The permitting authority will accept an allowance allocation request only if the request meets, or is adjusted by the permitting authority as necessary to meet, the requirements of paragraphs (c)(2) and (3) of this section.

(ii) On or after July 1 of the control period, the permitting authority will determine the sum of the Hg allowances requested (as adjusted under paragraph (c)(4)(i) of this section) in all allowance allocation requests accepted under paragraph (c)(4)(i) of this section for the control period.

(iii) If the amount of Hg allowances in the new unit set-aside for the control period is greater than or equal to the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate the amount of Hg allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each Hg Budget unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) If the amount of Hg allowances in the new unit set-aside for the control period is less than the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate to each Hg Budget unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the Hg allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of Hg allowances in the new unit set-aside for the control period, divided by the sum determined under paragraph (c)(4)(ii) of this section, and rounded to the nearest whole allowance as appropriate.

(v) The permitting authority will notify each Hg designated representative that submitted an allowance allocation request of the amount of Hg allowances (if any) allocated for the control period to the Hg Budget unit covered by the request.

(d) If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated Hg allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each Hg Budget unit that was allocated Hg allowances under paragraph (b) of this section an amount of Hg allowances equal to the total amount of such remaining unallocated Hg allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 95 percent for 2010 through 2014, and 97 percent for 2014 and thereafter, of the amount of ounces (*i.e.* , tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under §60.4140, and rounded to the nearest whole allowance as appropriate.

Hg Allowance Tracking System

§ 60.4150 [Reserved]

§ 60.4151 Establishment of accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under §60.4113, the Administrator will establish a compliance account for the Hg Budget source for which the certificate of representation was submitted unless the source already has a compliance account.

(b) *General accounts* —(1) *Application for general account.* (i) Any person may apply to open a general account for the purpose of holding and transferring Hg allowances. An application for a general account may designate one and only one Hg authorized account representative and one and only one alternate Hg authorized account representative who may act on behalf of the Hg authorized account representative. The agreement by which the alternate Hg authorized account representative is selected shall include a procedure for authorizing the alternate Hg authorized account representative to act in lieu of the Hg authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the Hg authorized account representative and any alternate Hg authorized account representative;

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the Hg authorized account representative and any alternate Hg authorized account representative to represent their ownership interest with respect to the Hg allowances held in the general account;

(D) The following certification statement by the Hg authorized account representative and any alternate Hg authorized account representative: "I certify that I was selected as the Hg authorized account representative or the alternate Hg authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to Hg allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the Hg Budget Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account."

(E) The signature of the Hg authorized account representative and any alternate Hg authorized account representative and the dates signed.

(iii) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of Hg authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The Hg authorized account representative and any alternate Hg authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to Hg allowances held in the general account in all matters pertaining to the Hg Budget Trading Program, notwithstanding any agreement between the Hg authorized account representative or any alternate Hg authorized account representative and such person. Any such person shall be bound by any order or decision issued to the Hg authorized account representative or any alternate Hg authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate Hg authorized account representative shall be deemed to be a representation, action, inaction, or submission by the Hg authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the Hg authorized account representative or any alternate Hg authorized account representative for the persons having an ownership interest with respect to Hg allowances held in the general account. Each such submission shall include the following certification statement by the Hg authorized account representative or any alternate Hg authorized account representative: “I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the Hg allowances held in the general account. 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.”

(iii) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) Changing Hg authorized account representative and alternate Hg authorized account representative; changes in persons with ownership interest.

(i) The Hg authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous Hg authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new Hg authorized account representative and the persons with an ownership interest with respect to the Hg allowances in the general account.

(ii) The alternate Hg authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate Hg authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate Hg authorized account representative and the persons with an ownership interest with respect to the Hg allowances in the general account.

(iii)(A) In the event a new person having an ownership interest with respect to Hg allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the Hg authorized account representative and any alternate Hg authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the new person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to Hg allowances in the general account, including the addition of persons, the Hg authorized account representative or any alternate Hg authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the Hg allowances in the general account to include the change.

(4) *Objections concerning Hg authorized account representative.* (i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the Hg authorized account representative or any alternative Hg authorized account representative for a general account shall affect any representation, action, inaction, or submission of the Hg authorized account representative or any alternative Hg authorized account representative or the finality of any decision or order by the Administrator under the Hg Budget Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the Hg authorized account representative or any alternative Hg authorized account representative for a general account, including private legal disputes concerning the proceeds of Hg allowance transfers.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

§ 60.4152 Responsibilities of Hg authorized account representative.

Following the establishment of a Hg Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of Hg allowances in the account, shall be made only by the Hg authorized account representative for the account.

§ 60.4153 Recordation of Hg allowance allocations.

(a) By December 1, 2006, the Administrator will record in the Hg Budget source's compliance account the Hg allowances allocated for the Hg Budget units at a source, as submitted by the permitting authority in accordance with §60.4141(a), for the control periods in 2010, 2011, 2012, 2013, and 2014.

(b) By December 1, 2008, the Administrator will record in the Hg Budget source's compliance account the Hg allowances allocated for the Hg Budget units at the source, as submitted by the permitting authority or as determined by the Administrator in accordance with §60.4141(b), for the control period in 2015.

(c) In 2011 and each year thereafter, after the Administrator has made all deductions (if any) from a Hg Budget source's compliance account under §60.4154, the Administrator will record in the Hg Budget source's compliance account the Hg allowances allocated for the Hg Budget units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with §60.4141(b), for the control period in the sixth year after the year of the control period for which such deductions were or could have been made.

(d) By December 1, 2010 and December 1 of each year thereafter, the Administrator will record in the Hg Budget source's compliance account the Hg allowances allocated for the Hg Budget units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with §60.4141(c), for the control period in the year of the applicable deadline for recordation under this paragraph.

(e) *Serial numbers for allocated Hg allowances.* When recording the allocation of Hg allowances for a Hg Budget unit in a compliance account, the Administrator will assign each Hg allowance a unique identification number that will include digits identifying the year of the control period for which the Hg allowance is allocated.

§ 60.4154 Compliance with Hg budget emissions limitation.

(a) *Allowance transfer deadline.* The Hg allowances are available to be deducted for compliance with a source's Hg Budget emissions limitation for a control period in a given calendar year only if the Hg allowances:

(1) Were allocated for the control period in the year or a prior year;

(2) Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a Hg allowance transfer correctly submitted for recordation under §§60.4160 through 60.4162 by the allowance transfer deadline for the control period; and

(3) Are not necessary for deductions for excess emissions for a prior control period under paragraph (d) of this section.

(b) *Deductions for compliance.* Following the recordation, in accordance with §§60.4160 through 60.4162, of Hg allowance transfers submitted for recordation in a source's compliance account by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account Hg allowances available under paragraph (a) of this section in order to determine whether the source meets the Hg Budget emissions limitation for the control period, as follows:

(1) Until the amount of Hg allowances deducted equals the number of ounces of total Hg emissions, determined in accordance with §§60.4170 through 60.4176, from all Hg Budget units at the source for the control period; or

(2) If there are insufficient Hg allowances to complete the deductions in paragraph (b)(1) of this section, until no more Hg allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of Hg allowances by serial number.* The Hg authorized account representative for a source's compliance account may request that specific Hg allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the Hg Budget source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct Hg allowances under paragraph (b) or (d) of this section from the source's compliance account, in the absence of an identification or in the case of a partial identification of Hg allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any Hg allowances that were allocated to the units at the source, in the order of recordation; and then

(ii) Any Hg allowances that were allocated to any unit and transferred and recorded in the compliance account pursuant to §§60.4160 through 60.4162, in the order of recordation.

(d) *Deductions for excess emissions.* (1) After making the deductions for compliance under paragraph (b) of this section for a control period in a calendar year in which the Hg Budget source has excess emissions, the Administrator will deduct from the source's compliance account an amount of Hg allowances, allocated for the control period in the immediately following calendar year, equal to 3 times the number of ounces of the source's excess emissions.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the Hg Budget source or the Hg Budget units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the Clean Air Act or applicable State law.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) or (d) of this section.

(f) *Administrator's action on submissions.* (1) The Administrator may review and conduct independent audits concerning any submission under the Hg Budget Trading Program and make appropriate adjustments of the information in the submissions.

(2) The Administrator may deduct Hg allowances from or transfer Hg allowances to a source's compliance account based on the information in the submissions, as adjusted under paragraph (f)(1) of this section.

§ 60.4155 Banking.

(a) Hg allowances may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any Hg allowance that is held in a compliance account or a general account will remain in such account unless and until the Hg allowance is deducted or transferred under §60.4154, §60.4156, or §§60.4160 through 60.4162.

§ 60.4156 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Hg Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the Hg authorized account representative for the account.

§ 60.4157 Closing of general accounts.

(a) The Hg authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under §60.4160 through 60.4162 for any Hg allowances in the account to one or more other Hg Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any Hg allowances, the Administrator may notify the Hg authorized account representative for the account that the account will be closed following 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of Hg allowances into the account under §60.4160 through 60.4162 or a statement submitted by the Hg authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

Hg Allowance Transfers

§ 60.4160 Submission of Hg allowance transfers.

An Hg authorized account representative seeking recordation of a Hg allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the Hg allowance transfer shall include the following elements, in a format specified by the Administrator:

(a) The account numbers for both the transferor and transferee accounts;

(b) The serial number of each Hg allowance that is in the transferor account and is to be transferred; and

(c) The name and signature of the Hg authorized account representative of the transferor account and the date signed.

§ 60.4161 EPA recordation.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a Hg allowance transfer, the Administrator will record a Hg allowance transfer by moving each Hg allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under §60.4160; and

(2) The transferor account includes each Hg allowance identified by serial number in the transfer.

(b) A Hg allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any Hg allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under §60.4154 for the control period immediately before such allowance transfer deadline.

(c) Where a Hg allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 60.4162 Notification.

(a) *Notification of recordation.* Within 5 business days of recordation of a Hg allowance transfer under §60.4161, the Administrator will notify the Hg authorized account representatives of both the transferor and transferee accounts.

(b) *Notification of non-recordation.* Within 10 business days of receipt of a Hg allowance transfer that fails to meet the requirements of §60.4161(a), the Administrator will notify the Hg authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a Hg allowance transfer for recordation following notification of non-recordation.

Monitoring and Reporting

§ 60.4170 General requirements.

The owners and operators, and to the extent applicable, the Hg designated representative, of a Hg Budget unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter. For purposes of complying with such requirements, the definitions in §60.4102 and in §72.2 of this chapter shall apply, and the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “Hg Budget unit,” “Hg designated representative,” and “continuous emission monitoring system” (or “CEMS”) respectively, as defined in §60.4102. The owner or operator of a unit that is not a Hg Budget unit but that is monitored under §75.82(b)(2)(i) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a Hg Budget unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each Hg Budget unit shall:

(1) Install all monitoring systems required under this section and §§60.4171 through 60.4176 for monitoring Hg mass emissions and individual unit heat input (including all systems required to monitor Hg concentration, stack gas moisture content, stack gas flow rate, and CO_2or O_2concentration, as applicable, in accordance with §§75.81 and 75.82 of this chapter);

(2) Successfully complete all certification tests required under §60.4171 and meet all other requirements of this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* The owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a Hg Budget unit that commences commercial operation before July 1, 2008, by January 1, 2009.

(2) For the owner or operator of a Hg Budget unit that commences commercial operation on or after July 1, 2008, by the later of the following dates:

(i) January 1, 2009; or

(ii) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a Hg Budget unit for which construction of a new stack or flue or installation of add-on Hg emission controls, a flue gas desulfurization system, a selective catalytic reduction system, or a compact hybrid particulate collector system is completed after the applicable deadline under paragraph (b)(1) or (2) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue, add-on Hg emissions controls, flue gas desulfurization system, selective catalytic reduction system, or compact hybrid particulate collector system.

(c) *Reporting data.* (1) Except as provided in paragraph (c)(2) of this section, the owner or operator of a Hg Budget unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for Hg concentration, stack gas flow rate, stack gas moisture content, and any other parameters required to determine Hg mass emissions and heat input in accordance with §75.80(g) of this chapter.

(2) The owner or operator of a Hg Budget unit that does not meet the applicable compliance date set forth in paragraph (b)(3) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in subpart D of part 75 of this chapter, in lieu of the maximum potential (or, as appropriate, minimum potential) values, for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under paragraph (b)(3) of this section.

(d) *Prohibitions.* (1) No owner or operator of a Hg Budget unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this section and §§60.4171 through 60.4176 without having obtained prior written approval in accordance with §60.4175.

(2) No owner or operator of a Hg Budget unit shall operate the unit so as to discharge, or allow to be discharged, Hg emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter.

(3) No owner or operator of a Hg Budget unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording Hg mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter.

(4) No owner or operator of a Hg Budget unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under §60.4105 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The Hg designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with §60.4171(c)(3)(i).

§ 60.4171 Initial certification and recertification procedures.

(a) The owner or operator of a Hg Budget unit shall be exempt from the initial certification requirements of this section for a monitoring system under §60.4170(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendix B to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under §60.4170(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) Except as provided in paragraph (a) of this section, the owner or operator of a Hg Budget unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (*e.g.* , a continuous emission monitoring system and an excepted monitoring system (sorbent trap monitoring system) under §75.15) under §60.4170(a)(1). The owner or operator of a unit that qualifies to use the Hg low mass emissions excepted monitoring methodology under §75.81(b) of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (d) or (e) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each monitoring system under §60.4170(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §60.4170(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system, or an excepted monitoring system (sorbent trap monitoring system) under §75.15, under §60.4170(a)(1) that may significantly affect the ability of the system to accurately measure or record Hg mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of §75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with §75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system, and each excepted monitoring system (sorbent trap monitoring system) under §75.15, whose accuracy is potentially affected by the change, in accordance with §75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site.

(3) *Approval process for initial certification and recertification.* Paragraphs (c)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under §60.4170(a)(1). For recertifications, apply the word “recertification” instead of the words “certification” and “initial certification” and apply the word “recertified” instead of the word “certified,” and follow the procedures in §75.20(b)(5) of this chapter in lieu of the procedures in paragraph (c)(3)(v) of this section.

(i) *Notification of certification.* The Hg designated representative shall submit to the permitting authority, the appropriate EPA Regional Office, and the Administrator written notice of the dates of certification testing, in accordance with §60.4173.

(ii) *Certification application.* The Hg designated representative shall submit to the permitting authority a certification application for each monitoring system. A complete certification application shall include the information specified in §75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the Hg Budget Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system under paragraph (c)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the permitting authority.

(iv) *Certification application approval process.* The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (c)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the Hg Budget Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the Hg designated representative must submit the additional information required to complete the certification application. If the Hg designated representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (c)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (c)(3)(iv)(B) of this section is met, then the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (c)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) *Audit decertification.* The permitting authority may issue a notice of disapproval of the certification status of a monitor in accordance with §60.4172(b).

(v) *Procedures for loss of certification.* If the permitting authority issues a notice of disapproval of a certification application under paragraph (c)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (c)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), or §75.21(e) of this chapter and continuing until the applicable date and hour specified under §75.20(a)(5)(i) of this chapter:

(*1*) For a disapproved Hg pollutant concentration monitors and disapproved flow monitor, respectively, the maximum potential concentration of Hg and the maximum potential flow rate, as defined in sections 2.1.7.1 and 2.1.4.1 of appendix A to part 75 of this chapter; and

(*2*) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2concentration or the minimum potential O_2concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(*3*) For a disapproved excepted monitoring system (sorbent trap monitoring system) under §75.15 and disapproved flow monitor, respectively, the maximum potential concentration of Hg and maximum potential flow rate, as defined in sections 2.1.7.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(B) The Hg designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (c)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the permitting authority's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(d) *Initial certification and recertification procedures for units using the Hg low mass emission excepted methodology under §75.81(b) of this chapter.* The owner or operator of a unit qualified to use the Hg low mass emissions (HgLME) excepted methodology under §75.81(b) of this chapter shall meet the applicable certification and recertification requirements in §75.81(c) through (f) of this chapter.

(e) *Certification/recertification procedures for alternative monitoring systems.* The Hg designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of §75.20(f) of this chapter.

§ 60.4172 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D of part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under §60.4171 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in §60.4171 for each disapproved monitoring system.

§ 60.4173 Notifications.

The Hg designated representative for a Hg Budget unit shall submit written notice to the permitting authority and the Administrator in accordance with §75.61 of this chapter, except that if the unit is not subject to an Acid Rain emissions limitation, the notification is only required to be sent to the permitting authority.

§ 60.4174 Recordkeeping and reporting.

(a) *General provisions.* (1) The Hg designated representative shall comply with all recordkeeping and reporting requirements in this section and the requirements of §60.4110(e)(1).

(2) If a Hg Budget unit is subject to an Acid Rain emission limitation or the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, or CAIR NO_X Ozone Season Trading Program, and the Hg designated representative who signed and certified any submission that is made under subpart F or G of part 75 of this chapter and that includes data and information required under this section, §§60.4170 through 60.4173, §60.4175, §60.4176, or subpart I of part 75 of this chapter is not the same person as the designated representative or alternative designated representative, or the CAIR designated representative or alternate CAIR designated representative, for the unit under part 72 of this chapter and the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, or CAIR NO_X Ozone Season Trading Program, then the submission must also be signed by the designated representative or alternative designated representative, or the CAIR designated representative or alternate CAIR designated representative, as applicable.

(b) *Monitoring plans.* The owner or operator of a Hg Budget unit shall comply with requirements of §75.84(e) of this chapter.

(c) *Certification applications.* The Hg designated representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under §60.4171, including the information required under §75.63 of this chapter.

(d) *Quarterly reports.* The Hg designated representative shall submit quarterly reports, as follows:

(1) The Hg designated representative shall report the Hg mass emissions data and heat input data for the Hg Budget unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2008, the calendar quarter covering January 1, 2009 through March 31, 2009; or

(ii) For a unit that commences commercial operation on or after July 1, 2008, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §60.4170(b), unless that quarter is the third or fourth quarter of 2008, in which case reporting shall commence in the quarter covering January 1, 2009 through March 31, 2009.

(2) The Hg designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.84(f) of this chapter.

(3) For Hg Budget units that are also subject to an Acid Rain emissions limitation or the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, or CAIR NO_X Ozone Season Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the Hg mass emission data, heat input data, and other information required by this section, §§60.4170 through 60.4173, §60.4175, and §60.4176.

(e) *Compliance certification.* The Hg designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this section, §§60.4170 through 60.4173, §60.4175, §60.4176, and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on Hg emission controls, a flue gas desulfurization system, a selective catalytic reduction system, or a compact hybrid particulate collector system and for all hours where Hg data are substituted in accordance with §75.34(a)(1) of this chapter, the Hg add-on emission controls, flue gas desulfurization system, selective catalytic reduction system, or compact hybrid particulate collector system were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter, or quality-assured SO_2 emission data recorded in accordance with part 75 of this chapter document that the flue gas desulfurization system, or quality-assured NO_X emission data recorded in accordance with part 75 of this chapter document that the selective catalytic reduction system, was operating properly, as applicable, and the substitute data values do not systematically underestimate Hg emissions.

§ 60.4175 Petitions.

The Hg designated representative of a Hg unit may submit a petition under §75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of §§60.4170 through 60.4174 and §60.4176. Application of an alternative to any requirement of §§60.4170 through 60.4174 and §60.4176 is in accordance with this section and §§60.4170 through 60.4174 and §60.4176 only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

§ 60.4176 Additional requirements to provide heat input data.

The owner or operator of a Hg Budget unit that monitors and reports Hg mass emissions using a Hg concentration monitoring system and a flow monitoring system shall also monitor and report heat input rate at the unit level using the procedures set forth in part 75 of this chapter.

SECTION G.6 New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

(i) One (1) diesel-fired emergency generator designated as EMDSL, permitted in 2008, with a maximum rating of 2200 brake-horsepower (Bhp), exhausting to Stack S-7.

Under the NSPS for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60, Subpart IIII), this emission unit is considered a model year 2007 or later emergency stationary internal combustion engine.

(j) One (1) diesel-fired emergency fire pump (FIRPMP), permitted in 2008, with a maximum rating of 420 brake-horsepower (Bhp) exhausting to stack S-8.

Under the NSPS for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60, Subpart IIII), this emission unit is considered to be a stationary CI ICE commencing construction after July 11, 2005, where the stationary CI ICE is manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

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

G.6.1 General Provisions Relating to NSPS Subpart IIII [326 IAC 12-1] [40 CFR 60, Subpart A]

The provisions of 40 CFR 60 Subpart A - General Provisions, which are incorporated as 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR 60 Subpart IIII.

G.6.2 NSPS for Stationary Compression Ignition Internal Combustion Engines [40 CFR Part 60, Subpart IIII]

Pursuant to 40 CFR Part 60, Subpart IIII, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart IIII, upon startup of the affected units, as follows:

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Intentionally omitted.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are:

(i) Manufactured after April 1, 2006 and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Intentionally omitted.

(b) Intentionally omitted.

(c) Intentionally omitted.

(d) Intentionally omitted.

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

Intentionally omitted.

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

Intentionally omitted.

§ 60.4203 How long must my engines meet the emission standards if I am a stationary CI internal combustion engine manufacturer?

Intentionally omitted.

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

Intentionally omitted.

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (d)(1) and (2) of this section.

(1) Reduce NO_X emissions by 90 percent or more, or limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (1.2 grams per HP-hour).

(2) Reduce PM emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(d) Intentionally omitted.

(e) Intentionally omitted.

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in the previous model year?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (f) of this section after the dates specified in paragraphs (a) through (f) of this section.

(h) Intentionally omitted.

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

Intentionally omitted.

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited.

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (d) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (d) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i = concentration of NO_X or PM at the control device inlet,

C_o = concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\,O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm ^{3} /J (dscf/10 ^{6} Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm ^{3} /J (dscf/10 ^{6} Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Intentionally omitted.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

Intentionally omitted.

§ 60.4216 What requirements must I meet for engines used in Alaska?

Intentionally omitted.

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Intentionally omitted.

General Provisions

§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§ 60.4219 What definitions apply to this subpart?

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

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means either:

(1) The calendar year in which the engine was originally produced, or

(2) The annual new model production period of the engine manufacturer if it is different than the calendar year. This must include January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year. For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was originally produced.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

Useful life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for useful life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for useful life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Tables to Subpart IIII of Part 60

Table 1 to Subpart IIII of Part 60._ Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder
[As stated in §§ 60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)....................	10.5 (7.8)	....	....	8.0 (6.0)	1.0 (0.75)
8[le]KW<19 (11[le]HP<25)........	9.5 (7.1)	....	....	6.6 (4.9)	0.80 (0.60)
19[le]KW<37 (25[le]HP<50).......	9.5 (7.1)	....	....	5.5 (4.1)	0.80 (0.60)
37[le]KW<56 (50[le]HP<75)....	....	....	9.2 (6.9)	....	
56[le]KW<75 (75[le]HP<100)...	....	....	9.2 (6.9)	....	
75[le]KW<130 (100[le]HP<175).	....	....	9.2 (6.9)	....	
130[le]KW<225 (175[le]HP<300)	....	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225[le]KW<450 (300[le]HP<600).	....	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450[le]KW[le]560 (600[le]HP[le]750)	....	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)..............	....	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60._Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in § 60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X + NMHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8[le]KW<19 (11[le]HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19[le]KW<37 (25[le]HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60._Certification Requirements for Stationary Fire Pump Engines

[As stated in § 60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:]

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to § 60.4202(d)
KW<75 (HP<100)	2011
75[le]KW<130 (100[le]HP<175)	2010
130[le]KW[le]560 (175[le]HP[le]750)	2009
KW>560 (HP>750)	2008

Table 4 to Subpart IIII of Part 60._ Emission Standards for Stationary Fire Pump Engines

[As stated in §§ 60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
225[le]KW<450 (300[le]HP<600)	2008 and earlier 2009+ \3\	10.5 (7.8) 4.0 (3.0)	3.5 (2.6)	0.54 (0.40) 0.20 (0.15

\3\ In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60 - Labeling and Recordkeeping Requirements for New Stationary Emergency Engines
[You must comply with the labeling requirements in § 60.4210(f) and the recordkeeping requirements in § 60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19[le]KW<56 (25[le]HP<75)	2013
56[le]KW<130 (75[le]HP<175)	2012
KW>=130 (HP>=175)	2011

Table 6 to Subpart IIII of Part 60._Optional 3-Mode Test Cycle for Stationary Fire Pump Engines
[As stated in § 60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed \1\	Torque (percent) \2\	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

\1\ Engine speed: ±2 percent of point.
\2\ Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60._Requirements for Performance Tests for Stationary CI ICE With a Displacement of >=30 Liters per Cylinder
[As stated in § 60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of >=30 liters per cylinder:]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1.Stationary CI internal combustion engine with a displacement of >=30 liters per cylinder.	a. Reduce NO_X emissions by 90 percent or more.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at	(2) Method 3, 3A,	(b) Measurements

to determine O_2 concentration must be made at same time as measurements NO_X concentration.		the inlet and outlet of the control device;	or 3B of 40 CFR part 60, appendix A.	the the for
Measurements to determine moisture content must be made at same time as measurements concentration.		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17).	(c) the the for NO_X
NO_X concentration must be at 15 percent O_2, dry Results of consist average of three 1-hour longer runs.		iv. Measure NO_X at the inlet and outlet of the control device.	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17).	(d) basis. this test of the the or
If using a control device, the sampling site	b. Limit the concentration of NO_X in the	i. Select the sampling port location and the	(1) Method 1 or 1A of 40 CFR part 60, Appendix A.	(a)

be located
outlet of
control

Measurements
determine O_2
concentration
be made at
the same time as
measurement

Measurements
to determine
moisture content
made at
time as
the measurement
for NO_X
concentration.

(d) NO_X
concentration
must be at 15
O_2, dry
basis. Results of
consist
average of
three 1-hour

stationary CI
internal
combustion engine
exhaust.

number of
traverse points;

ii. Determine the
O_2 concentration
of the stationary
internal
combustion engine
exhaust at the
sampling port
location; and,

iii. If necessary,
measure moisture
content of the
stationary
internal
combustion engine
exhaust at the
sampling port
location; and,

iv. Measure NO_X at
the exhaust of
the stationary
internal
combustion engine.

(2) Method 3, 3A,
or 3B of 40 CFR
part 60, appendix
A.

(3) Method 4 of 40
CFR part 60,
appendix A,
Method 320 of 40
CFR part 63,
appendix A, or
ASTM D 6348-03
(incorporated by
reference, see
§ 60.17).

(4) Method 7E of
40 CFR part 60,
appendix A,
Method 320 of 40
CFR part 63,
appendix A, or
ASTM D 6348-03
(incorporated by

must
at the
the
device.

(b)
to
must
the
for NO_X
concentration.

(c)
must be
the same
percent
this test
of the
the

longer runs.

(a) Sampling sites must be located at the inlet and of the control device. Measurements to determine O_2 concentration must be made at same time as measurements concentration. Measurements determine and moisture content be made at same time as measurements concentration.

(d) PM concentration at 15 percent O_2, dry basis. Results of test consist

c. Reduce PM emissions by 60 percent or more.

reference, see or § 60.17).

i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	outlet
ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A.	(b) the the for PM
iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A.	(c) to must the the for PM
iv. Measure PM at the inlet and outlet of the control device.	(4) Method 5 of 40 CFR part 60, appendix A.	must be this

average of three 1-hour longer runs. using a control device, the sampling site be located the outlet of control	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, Appendix A.	of the the or (a) If must at the device.
Measurements determine O_2 concentration made at the same time as measurements concentration.		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A.	(b) to must be the for PM
Measurements determine moisture content made at time as the measurements concentration.		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A.	(c) to must be the same for PM
PM concentration be at 15		iv. Measure PM at the exhaust of the stationary	(4) Method 5 of 40 CFR part 60, appendix A.	(d) must

internal combustion engine.

percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Table 8 to Subpart IIII of Part 60 - Applicability of General Provisions to Subpart IIII

[As stated in § 60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.1	General applicability of the General Provisions.	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4219.
§ 60.3	Units and abbreviations	Yes.	
§ 60.4	Address.	Yes.	
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.9	Availability of information.	Yes.	
§ 60.10	State Authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No	Requirements are specified in subpart IIII.
§ 60.12	Circumvention	Yes.	
§ 60.14	Modification	Yes.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	Yes.	
§ 60.17	Incorporations by reference.	Yes.	
§ 60.18	General control device requirements.	No.	
§ 60.19	General notification and reporting requirements.	Yes.	

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY

PART 70 OPERATING PERMIT
CERTIFICATION

Source Name:	Duke Energy Indiana, Inc. - Edwardsport Generating Station
Source Address:	15424 East State Road 358, Edwardsport, Indiana 47258
Mailing Address:	c/o Mack Sims, 1000 East Main Street, Plainfield, Indiana 46168
Part 70 Permit No.:	T 083-7243-00003

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

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify): ____________________

☐ Report (specify): ____________________

☐ Notification (specify): ____________________

☐ Affidavit (specify): ____________________

☐ Other (specify): ____________________

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

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

OFFICE OF AIR QUALITY
COMPLIANCE BRANCH

100 North Senate Avenue
MC 61-53, IGCN 1003
Indianapolis, Indiana 46204-2251
Phone: 317-233-0178
Fax: 317-233-6865

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: Duke Energy Indiana, Inc. - Edwardsport Generating Station
Source Address: 15424 East State Road 358, Edwardsport, Indiana 47258
Mailing Address: c/o Mack Sims, 1000 East Main Street, Plainfield, Indiana 46168
Part 70 Permit No.: T 083-7243-00003

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**) 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 Describe: 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: ______________________________

Attach a signed certification to complete this report.

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

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

Source Name: Duke Energy Indiana, Inc. - Edwardsport Generating Station
Source Address: 15424 East State Road 358, Edwardsport, Indiana 47258
Mailing Address: c/o Mack Sims, 1000 East Main Street, Plainfield, Indiana 46168
Part 70 Permit No.: T 083-7243-00003

Emission Unit: ____

☐ Natural Gas Only

☐ Alternate Fuel burned

From: _____ To: _____

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

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

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

Part 70 Quarterly Report

Source Name: Duke Energy Indiana, Inc. - Edwardsport Generating Station
Source Address: 15424 East State Road 358, Edwardsport, Indiana 47258
Mailing Address: c/o Mack Sims, 1000 East Main Street, Plainfield, Indiana 46168
Part 70 Permit No.: T 083-7243-00003
Emission Unit: ____________________
Parameter: ____________________
Limit: ____________________

YEAR: _____

Month	Syngas Usage for This Month (gallons)	Syngas Usage for Previous 11 Months (gallons)	Syngas Usage for 12-Month Period (gallons)

☐ No deviation occurred in this quarter.

☐ Deviations occurred in this quarter.
Deviation has been reported on: ____________________

Submitted By: ____________________

Title/Position: ____________________

Signature: ____________________

Date: ____________________

Phone: ____________________

Attach a signed certification to complete this report.

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

Part 70 Quarterly Report

Source Name: Duke Energy Indiana, Inc. - Edwardsport Generating Station
Source Address: 15424 East State Road 358, Edwardsport, Indiana 47258
Mailing Address: c/o Mack Sims, 1000 East Main Street, Plainfield, Indiana 46168
Part 70 Permit No.: T 083-7243-00003
Emission Unit: ______________________________
Parameter: ______________________________
Limit: ______________________________

YEAR: _____

Month	Diesel Fuel Oil Usage for This Month (gallons)	Diesel Fuel Oil Usage for Previous 11 Months (gallons)	Diesel Fuel Oil Usage for 12-Month Period (gallons)

☐ No deviation occurred in this quarter.

☐ Deviations occurred in this quarter.
Deviation has been reported on: ____________________

Submitted By: ______________________________

Title/Position: ______________________________

Signature: ______________________________

Date: ______________________________

Phone: ______________________________

Attach a signed certification to complete this report.

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

PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Duke Energy Indiana, Inc. - Edwardsport Generating Station
Source Address: 15424 East State Road 358, Edwardsport, Indiana 47258
Mailing Address: c/o Mack Sims, 1000 East Main Street, Plainfield, Indiana 46168
Part 70 Permit No.: T 083-7243-00003

Months: __________ **to** __________ **Year:** ________

Page 1 of 2

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

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

Form Completed By: ____________________

Title/Position: ____________________

Date: ____________________

Phone: ____________________

Attach a signed certification to complete this report.

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (ATSD)
PSD/Significant Source Modification (SSM) of a Part 70 Source
Significant Permit Modification (SPM) of a Part 70 Operating Permit

Source Description and Location

Source Name:	**Duke Energy Indiana - Edwardsport Generating Station**
Source Location:	**15424 East State Rd 358, Edwardsport, IN 47258**
County:	**Knox**
SIC Code:	**4911**
Operation Permit No.:	**T 083-7243-00003**
Operation Permit Issuance Date:	**August 10, 2004**
PSD/Significant Source Modification No.:	**PSD/SSM 083-28683-00003**
Significant Permit Modification No.:	**SPM 083-28801-00003**
Permit Reviewer:	**Josiah Balogun**

Public Notice Information

On December 24, 2009, the Office of Air Quality (OAQ) had a notice published in the Sun Commercial in Vincennes, Indiana, stating that Duke Energy Indiana - Edwardsport Generating Station had applied for a PSD/Significant Modification to their Part 70 Operating Permit issued on August 10, 2004.This application constitutes a request for a PSD permit revision to address certain revisions and additions to the coal and lime material handling emission units of the proposed IGCC plant at the Edwardsport generating facility. Since this request presents design changes to facilities and operations previously reviewed and permitted by IDEM under the PSD rules these changes will be considered part of the original project and addressed in a revision to the previously issued PSD permit in 2008. The additional and revised equipments that are the subject of this source modification will emit only PM/PM10/PM2.5. The notice also stated that OAQ proposed to issue a permit for this operation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

On January 27, 2010, the Office of Air Quality (OAQ) held a public meeting and hearing at the North Knox High School Auditorium in Bicknell, Indiana, for citizens and interested parties to discuss questions and concerns related to the project.

No changes have been made to the TSD because the OAQ prefers that the Technical Support Document reflects the permit that was on public notice. Changes that occur after the public notice are documented in this Addendum to the Technical Support Document. This accomplishes the desired result, ensuring that these types of concerns are documented and part of the record regarding this permit decision.

The summary of the comments and IDEM, OAQ responses, including changes to the permit (language deleted is shown in ~~strikeout~~ and language added is shown in **bold**) are as follows:

Comments Received from the Public

OAQ received public comments from David Bender of McGillivray, Westerberg, & Bender, LLC on behalf of Sierra Club, Valley Watch and Citizen Action Coalition of Indiana.

OAQ received comments from the following people (and groups of people):

David Bender, representing Sierra Club, Valley Watch and Citizen Action Coalition of Indiana

Zachary Elliot, representing Statewide Consumer Advocacy group

John Blair, representing Valley Watch, inc

David Keppel, representing Green Sanctuary Task Force of the Unitarian Universalist Church of Bloomington, Indiana

Jeannette Rowe	4980 W. 59th Street, Indianapolis, Indiana
Jim Stanley	President of Duke Energy, Indiana
Vincent L. Griffin	VP Environmental and Energy Policy, Indiana Chamber of Commerce

The comments are summarized in the subsequent pages, with IDEM's corresponding responses.

Comment 1: The draft permit fails to include a BACT limit for $PM_{2.5}$.

The Draft Permit does not include a BACT limit for $PM_{2.5}$ emissions from new and modified sources (including the new IGCC units and associated equipment), despite the fact that those new and modified units triggered the $PM_{2.5}$ BACT requirement (by being constructed after the date that $PM_{2.5}$ became a regulated pollutant). Because $PM_{2.5}$ is regulated pollutant that will be emitted in a significant amount, a BACT limit for $PM_{2.5}$ is required from units added or modified since 1997 (i.e., the IGCC units and associated equipment).

The U.S. EPA confirmed that using PM_{10} as a surrogate for $PM_{2.5}$ is not legally defensible by granting a petition seeking EPA's objection to a permit for the Trimble power plant because of the permit's lack of a $PM_{2.5}$ limit. *In re Louisville Gas & Electric Co.,* Petition No. IV-2008-3, Order at 42-46 (EPA Adm'r Aug. 12, 2009).

To the extent that IDEM relied upon a "surrogacy" policy to avoid a $PM_{2.5}$ BACT limit based on the PM_{10} limits in the permit, the record does not support that decision. Moreover, as EPA has held, the basis for a surrogacy policy is probably no longer defensible as the "practical difficulties" to establishing direct limits on $PM_{2.5}$ have been resolved.

PM_{10} and $PM_{2.5}$ are not equivalents. The Edwardsport plant will cause or contribute to violations of $PM_{2.5}$ NAAQS even though PM_{10} NAAQS may be protected. The U.S. EPA's promulgation of $PM_{2.5}$ NAAQS is premised upon the finding that PM_{10} and $PM_{2.5}$ are not equivalent and a $PM_{2.5}$ standard—rather than merely a PM_{10} standard-- was necessary to protect health and welfare. That finding cannot be effectively undone, by substituting PM_{10} through a guidance document, based upon administrative expediency.

Moreover, the guidance memos that have been used in the past to justify the use of PM_{10} as a surrogate for $PM_{2.5}$ are outdated. Any impracticalities referenced in the memo as the basis for using PM_{10} as a surrogate (modeling, emission calculations and estimates, etc.) have been resolved. Indeed, Indiana requires reporting of $PM_{2.5}$ emissions— demonstrating that the emission calculation and estimation issues have been resolved. 326 Indiana Administrative Code (IAC) 2-6-4(a)(7).

Response 1:

The IGCC emission units at the Edwardsport IGCC plant were first permitted in significant source modification 083-23529-00003 issued on January 25, 2008. On November 23, 2009,Duke Energy Indiana filed permit application 083-28683-00003 to make revisions to the design of certain previously permitted emitting equipment and the installation of additional emitting equipment for the coal handling system using enclosed conveyors and bunkers, and a lime and soda ash handling system that includes enclosed conveyors and silos. These revised and additional pieces of equipment (referred to as the "revised material handling equipment") will be incorporated in the construction of the IGCC plant. Accordingly, the application constituted a request for a Prevention of Significant Deterioration (PSD) Significant Source Modification and Title V Operating Permit (TVOP) Significant Permit Revision to address these new coal and lime/soda ash material handling units at the IGCC plant at the Edwardsport generating facility. The revised material handling equipment will result in a net decrease in particulate matter (PM) emissions in comparison to the previously permitted PM PM_{10} (fine particulate matter), and $PM_{2.5}$ (very fine particulate matter) emissions from these operations under the previous permit issued on January 25, 2008. Therefore, this modification is not a major modification as defined under PSD rules (326 Indiana Administrative Code 2-2). The modification is a PSD revision because it involves physical changes to emission units previously permitted under PSD that are not yet constructed or operational.

The United States Environmental Protection Agency (U.S. EPA) published a final rule establishing certain of the requirements needed for implementation of the PSD program for $PM_{2.5}$ on May 16, 2008, at 73 Federal Register (FR) 28321 ("May 2008 Rule"), including the identification of precursors to $PM_{2.5}$ and establishment of significant emission rates for $PM_{2.5}$ and its precursors. In the preamble to the May 2008 Rule (at 73 FR 28341), U.S. EPA announced that states with SIP-approved PSD programs have three years from the date of the May 2008 Rule to submit revised PSD programs for $PM_{2.5}$ to U.S. EPA for approval. U.S. EPA further provided in the May 2008 Rule preamble that, during the SIP development period, a state that is unable to implement a PSD program for $PM_{2.5}$ based on the May 2008 Rule may continue to implement a PM_{10} program as a surrogate to meet PSD program requirements for $PM_{2.5}$ pursuant to the 1997 guidance for such surrogate programs. Indiana has not yet completed SIP revisions to its PSD program rules to implement the $PM_{2.5}$ requirements, therefore, the PM_{10} surrogate program remains applicable for Indiana PSD projects.

On February 11, 2010, U.S. EPA published a proposed rule to end the PM_{10} surrogacy policy established by previous guidance and rules, including the May 2008 Rule. See 75 FR 6827. While U.S. EPA clearly expresses its intent to end the use of the PM_{10} surrogacy policy, U.S. EPA acknowledges that the surrogate policy "is in effect" (75 FR at 6833) and states that "EPA is proposing to end the PM_{10} Surrogate Policy before the end of the three-year transition period for revising SIPs . . . ." Thus, while U.S. EPA undoubtedly has concerns about continuing the surrogate policy, the policy remains in effect.

In the February 2010 proposed rule, U.S. EPA indicates that permit applicants or permitting authorities, in contemplating whether use of the PM_{10} Surrogate Policy is reasonable in a specific situation, should consider the differences between PM_{10} and $PM_{2.5}$ and demonstrate that PM_{10} is an adequate surrogate for $PM_{2.5}$ in light of those differences. This is the same position U.S. EPA took in its order granting a petition for objection to a Title V permit issued to a proposed coal-fired power plant generating unit in Kentucky, stating that the Kentucky permitting authority had failed to justify its application of the PM10 surrogate policy (In re Louisville Gas & Electric Co., Petition No. IV-2008-3 (EPA Adm'r, Aug. 12, 2009).

IDEM has determined that PM_{10} is a reasonable surrogate for $PM_{2.5}$ for purposes of this permit. The $PM_{2.5}$ emission units in this modification are used for handling, transporting and storing coal, lime and soda ash, resulting only in filterable PM emissions. Since there are no condensable emissions associated with this modification, it is reasonable to conclude that the filterable $PM_{2.5}$ would be equal to or less than the filterable PM_{10} emissions and that PM_{10} BACT analysis implicitly includes the consideration of reductions in $PM_{2.5}$.

U.S. EPA's AP-42 emission factors guidance contains information on the relative particle size distribution for uncontrolled particulate matter from aggregate material handling, which is comparable to the revised material handling operations in this permit (see AP-42, Sec. 13.2.4-4). The particle size factor for PM_{10} is 0.35 compared to a size factor of 0.053 for $PM_{2.5}$. This means that $PM_{2.5}$ represents 15% of PM_{10} for emissions from aggregate handling.

IDEM conducted a top-down BACT analysis of PM_{10} control technologies as part of its review and included it as Appendix B to the Technical Support Document. The control technologies evaluated for filterable PM_{10} included a wet scrubber, wet suppression, a cyclone and a fabric filter. IDEM made a final determination that a fabric filter was the top ranked control technology for PM_{10} and that BACT for the emission units under evaluation was a fabric filter achieving a maximum loading from the control device of 0.003 grains per dry standard cubic foot (dscf). This level of control is more stringent than any BACT limit reviewed for permits for other sources with similar emission units.

The fabric filter control devices determined to be BACT for PM_{10} will also provide the highest effective control for filterable $PM_{2.5}$. BACT analyses for the two PM species would differ only if another control technology offered improved control efficiency for $PM_{2.5}$ as compared to PM_{10}, or if a particular control technology could be omitted based on economics of the control cost for one PM fraction versus the other PM fraction. There is no indication of any such potential grounds for differing BACT results for PM_{10} and $PM_{2.5}$. A fabric filter control device will the most effective control of filterable $PM_{2.5}$ compared to all the other control technologies. U.S. EPA's AP-42 guidance provides information on relative control efficiencies of different control technologies for various PM species in Table 1.1-6 from AP-42's chapter "Bituminous and Subbituminous Coal Combustion". The table below shows that baghouse technology has the highest efficiency for $PM_{2.5}$ as it does for PM_{10}. Though this table was developed from control devices applied to boiler combustion rather than to material handling operations, the relative control efficiency data should be qualitatively valid for comparative purposes.

Extract from AP-42 Table 1.1-6.

Particle Size[b] (µm)		Cumulative Mass % ≥ Stated Size			
		Controlled			
	Uncontrolled	Multiple Cyclones	Scrubber ESP		Baghouse
15 32		54	81	79	97
10 23		29	71	67	92
6 17		14	62	50	77
2.5 6		3	51	29	53
1.25 2		1	35	17	31
1.00 2		1	31	14	25
0.625 1		1	20	12	14
Total 100		100	100	100	100

b: Expressed as aerodynamic equivalent diameter

Therefore, IDEM has determined that PM_{10} is a reasonable surrogate for $PM_{2.5}$ for purposes of this permit, including the establishment of the BACT requirements.

Comment 2: The draft permit fails to ensure that the plant will comply with ambient air quality standards for $PM_{2.5}$.

A Title V permit must ensure compliance with applicable requirements including 42 U.S.C. § 7475(a)(3), 326 IAC 2-2-4, 316 IAC 2-2-5, 326 IAC 2-2-16, 326 IAC 2-1.1-5, and the National Ambient Air Quality Standards (NAAQS). These provisions prohibit emissions that would cause and/or contribute to a NAAQS violation. This permit would allow emissions that cause violations of the $PM_{2.5}$ NAAQS.

IDEM should model the ambient impacts of $PM_{2.5}$, not PM_{10}. U.S. EPA articulated the dangers of $PM_{2.5}$ in its recent Fine Particle Implementation Rule, *Clean Air Fine Particle Implementation Rule*, 72 Federal Register (FR) 20586, 20586-20587 (Apr. 25, 2007) (to be codified at 40 C.F.R. Part 51). IDEM may not rely on U.S. EPA guidance memos. The EPA cannot repeat a regulation with guidance. Pettibone Corp. v. United States, 34 F.3d 536, 541 (7th Cir. 1994) (quoting EEOC v. Arabian American Oil Co., 499 U.S. 244, 260, 111 S. Ct. 1227 (1991)) (Scalia, J. concurring in part and in the judgment).

U.S. EPA's recommended use of PM_{10} as a surrogate for $PM_{2.5}$ expired by its own terms when U.S. EPA published the final $PM_{2.5}$ implementation rule in April 2007. The more recent Page Memo included a qualified reaffirmation of the surrogacy approach. The Page Memo noted that U.S. EPA recommended using PM_{10} as a surrogate for $PM_{2.5}$ "until [U.S. EPA] promulgate[s] the $PM_{2.5}$ implementation rule." U.S. EPA has published a proposed $PM_{2.5}$ implementation rule. The proposed rule made clear that the surrogacy approach expires when the proposed rule becomes final.

Commenters contend that the April 2007 PM2.5 rule affirms EPA's rejection of the surrogacy approach.

The commenters' engineer modeled the $PM_{2.5}$ emissions from the Edwardsport plant. The modeling results show that the $PM_{2.5}$ NAAQS (as well as U.S. EPA's proposed PSD increments) will be exceeded.

Response 2:

As set out in IDEM's Response 1 above, this permit allows revisions to the previously permitted design for coal handling and lime/soda ash storage facilities that will result in a net decrease in particulate emissions in comparison to the currently permitted PM/ PM_{10}/$PM_{2.5}$ emissions from these emission units. Therefore, this modification is not a major modification as defined under Prevention of Significant Deterioration (PSD) rules (326 Indiana Administrative Code (IAC) 2-2). The modification is a PSD revision only because it involves physical changes to emission units previously permitted under PSD that are not yet constructed or operational.

On April 25, 2007, the U.S. EPA finalized its $PM_{2.5}$ implementation rule ("April 2007 Rule"). The April 2007 Rule established:

(i) schedules for performance by the states of attainment demonstrations to define nonattainment areas for PM2.5,

(ii) requirements for developing SIP provisions to bring nonattainment areas into attainment, and

(iii) guidance for states' development of RACT and RACM requirements for facilitating attainment with the National Ambient Air Quality Standards (NAAQS).

However, the U.S. EPA decided not to include the New Source Review (NSR) program in the implementation rule and stated that, "because there was an interim surrogate NSR program in place" (which allowed states to use PM_{10} as a surrogate between the effective date of the $PM_{2.5}$ NAAQS designation and until the U.S. EPA promulgates major NSR regulations for the implementation of $PM_{2.5}$), EPA would finalize the NSR part of the rule in a separate rulemaking at a later date. On September 21, 2007, the U.S. EPA proposed a separate rulemaking that proposed $PM_{2.5}$ increments, Significant Impact Levels, and a Significant Monitoring Concentration to facilitate implementation of the $PM_{2.5}$ PSD program. The preamble to that rule cites the interim surrogate policy for use of PM_{10} in lieu of $PM_{2.5}$ as part of a transition program for $PM_{2.5}$ implementation in NSR.

U.S. EPA published a final rule establishing certain requirements needed for implementation of the PSD program for $PM_{2.5}$ on May 16, 2008, at 73 Federal Register (FR) 28321 ("May 2008 Rule"), including the identification of precursors to $PM_{2.5}$ and establishment of significant emission rates for $PM_{2.5}$ and its precursors. In the preamble to the May 2008 Rule (at 73 FR 28341), U.S. EPA announced that states like Indiana, which have SIP-approved PSD programs that require amendments to incorporate the elements of the May 2008 Rule have three years from the date of the May 2008 Rule to submit revised PSD programs for $PM_{2.5}$ to U.S. EPA for approval. EPA further provided in the May 2008 Rule preamble that, during this SIP development period, a state that is unable to implement a PSD program for $PM_{2.5}$ based on the May 2008 Rule, may continue to implement a PM_{10} program as a surrogate to meet PSD program requirements for $PM_{2.5}$ pursuant to the 1997 guidance for such surrogate programs. Since Indiana has not yet completed SIP revisions to its PSD program rules to implement the $PM_{2.5}$ requirements, the PM_{10} surrogate program remains applicable for PSD projects under review in this state. In the May 2008 Rule, U.S. EPA makes the following statement regarding the 3-year transition program for SIP-approved states:

> We have dropped the requirement [from proposed option 1 of the rule proposal] for demonstrating compliance with the $PM_{2.5}$ NAAQS in order to maintain consistency in the application of the existing surrogate policy across the PSD program during the interim period. Since in the final rule we are otherwise allowing SIP-approved states to continue with the PM_{10} surrogate policy to meet the PSD requirements for $PM_{2.5}$, partially implementing the PM_{10} surrogate policy in this manner would be confusing and difficult to administer. Thus, to ensure consistent administration during the transition period, we have elected to maintain our existing PM_{10} surrogate policy which only recommends as an interim measure that sources and reviewing authorities conduct the modeling necessary to show that PM_{10} emissions will not cause a violation of the PM_{10} NAAQS as a surrogate for demonstrating compliance with the $PM_{2.5}$ NAAQS.

73 FR 28321, 28341.

On February 11, 2010, U.S. EPA published a proposed rule to, among other things, end the PM_{10} surrogacy policy established by previous guidance and rules, including the May 2008 Rule (75 FR 6827). While U.S. EPA clearly expresses its intent to end the use of the PM_{10} surrogacy policy, it acknowledges that the surrogate policy "is in effect" (75 FR at 6833) and states that "EPA is proposing to end the PM_{10} Surrogate Policy before the end of the three-year transition period for revising SIPs . . . ." Thus, while EPA undoubtedly has concerns about continuing the surrogate policy, the policy remains in effect. It is not necessary to demonstrate compliance with the $PM_{2.5}$ NAAQS since the PM_{10} surrogate policy is applicable and, as explained in the previous Response to Comment 1, IDEM has determined that it is reasonable to use PM_{10} as a surrogate for $PM_{2.5}$ for this permitting action at this source. IDEM conducted modeling that demonstrated that emissions from the source with the revisions allowed in this permit will continue to comply with NAAQS for PM_{10}, which acts as a surrogate for a demonstration of compliance with the $PM_{2.5}$ NAAQS. The emission units added and other changes in this permit have decreased PM emissions making any additional modeling unnecessary.

Comment 3:

Another of the "applicable requirements" that must be included in a Title V permit is a best available control technology ("BACT") limit for new or modified facilities for "each regulated NSR pollutant for which the modification would result in a significant net emissions increase at the source." 326 IAC 2-2-3. The source has or is in the process of constructing or modifying the emission sources at the plant. [permitted by Significant Source Modification 23529, issued on January 25, 2008]

However, the draft permit does not include BACT limits for these emission sources for (NOx), sulfur dioxide (SO_2), sulfuric acid mist ("SAM" or H_2SO_4), and Beryllium (Be) because IDEM concluded that the emission increases from the construction would not be "significant." A "significant" increase is an increase greater than the thresholds in 326 IAC 2-2(ee). A "net increase" is the amount of increase from a construction or modification project after other contemporaneous and creditable increases and decreases are added, or subtracted. 326 IAC 2-2-1(jj). This calculation is known as a "netting analysis."[5] Decreases at the emission source are "creditable"—meaning they can be used to off-set other emission increases in a "netting analysis"— only to the extent that the old emissions were "allowable" and if the decrease "has approximately the same qualitative significance for public health and welfare as that attributable to the increase." 326 IAC 2-2-1(jj)(6). IDEM's netting analysis credited the source with emission decreases at plant for the proposed shutdown of four existing boilers and associated equipment at the plant. IDEM assumed that all of the historic emissions from the existing boilers and associated equipment was "allowable," pursuant to 326 IAC 2-2-1(jj)(6). In other words, IDEM allowed Duke Energy to take credit for the full amount of historic emissions from the existing sources in a netting analysis for the project to construct new emission sources.

The construction of new emission sources at the Duke plant will cause significant emission increases because the old level of emissions from the existing boilers and equipment vastly exceeded the allowable emissions from those sources. The plant underwent 15 projects after 1985, in addition to other projects, which constitute major modifications and subjected the plant to BACT emission limits for all regulated NSR pollutants.

Each of the projects was a physical change which resulted in a significant net emissions increase of one or more regulated NSR pollutants, and constituted a "major modification." The emission increases must be calculated with an actual-to-potential methodology for all projects, especially those occurring after July 21, 1992 because the facility opted-out of the optional actual-to-future-actual test provided in the 1992 WEPCO rulemaking. After each major modification the affected units were subject to BACT emission limitations, which were at least 98% control for SO_2, 90% control of NOx, 98% control of sulfuric acid mist (SAM), and 90% control of beryllium (Be) for the boilers. Notably, BACT limits must be at least as stringent as New Source Performance Standards, which would have required significant reductions in SO_2 and NOx. *See* 40 C.F.R. §§ 60.43a, 60.44a.

IDEM's netting analysis for the current project failed to account for the fact that the "creditable" emission reductions for the shutdown of the existing emission sources (to offset the emission increases from new sources) are only those historic emissions that complied with BACT and were therefore "allowable" emissions. 326 IAC 2-2-1(6)(A). A correct netting analysis, using only "allowable emissions," as required by 326 IAC 2-21(jj)(6)(A), results in significant net emission increases of NOx, SO_2, SAM and Be from the project. Therefore BACT emission limits are required for each of these pollutants. The permit fails to include such limits and must, therefore, be vacated or stayed unless and until such limits are included.

The historic emission rates for the existing Edwardsport units far exceed the NSPS and BACT for those units. It is our understanding that the existing units have been modified numerous times, within the meaning of 42 U.S.C. §§ 7411, 7475 and 326 IAC 2-2-2, prior to or during the 24-month "baseline" period. These modifications would constitute "major modifications" and trigger the NSPS and BACT limits for the units. Consequently, the "allowable" emissions for the units were much lower than the actual emissions and Duke may only take credit for the allowable emissions. Especially when combined with the updated "baseline" period, subtracting noncompliant historic emissions form the baseline results in significant net emission increases of NOx and SO_2 attributable to the proposed project. BACT limits must be determined and air impacts must be assessed for these pollutants before the final permit can issue.

Response 3:

These comments are not relevant to this permitting action. This permit revision only incorporates design changes to the coal and lime material handling emission units which emit only PM/ PM_{10}/$PM_{2.5}$. No changes have been proposed to any facilities that will emit pollutants such as NOx, SO_2, SAM or Be.

IDEM received comments that raised these issues during the public notice period of Significant Source Modification No. 083-23529-00003. IDEM responded to these comments in detail in the Addendum to the Technical Support Document prepared for Significant Source Modification No. 083-23529-00003, issued on January 25, 2008. Because no changes have been made to these provisions of the permit which were drawn directly from the construction permit, and IDEM is aware of no substantive changes in an area of law affecting the issues raised in the comment or IDEM's response to it, for the sake of convenience IDEM has decided to reproduce language from its previous response to the Significant Source Modification here:

The January 25, 2008 permit used a baseline period of June 2002 through May 2004 for establishing the contemporaneous emissions reductions for the netting analysis. On August 10, 2006, Duke Energy Indiana submitted the application to modify the source. IDEM allows the applicant to look back 5 years from the date of application rather than the date of construction because of the variability involved in processing air permit applications undergoing new source review. In addition, pursuant to 326 IAC 2-2-1(e)(1), IDEM evaluated the data and determined that the baseline period of June 2002 through May 2004 is representative of normal operations.

With regard to the requirement to exclude noncompliant emissions and emissions exceeding allowable emissions, IDEM is not aware of any exceedances or violations which occurred during the baseline period. Therefore, no adjustments were necessary for the baseline emissions.

Comment 4:

> The permit should contain BACT Limits for carbon dioxide (CO_2). The impacts of CO_2 emissions on human health and welfare through global warming are undeniable. Burning fossil fuels is the primary source of CO_2 emissions, and, therefore, the primary cause of global warming and resulting climate changes. If allowed to operate, the proposed plant will accelerate and exacerbate the negative effects of global warming. BACT limits are required because CO_2 is subject to regulation under the Clean Air Act. The draft permit omits this important applicable requirement.

Response 4:

This permit revision only incorporates design changes to the coal and lime material handling emission units which emit only PM/ PM_{10}/$PM_{2.5}$. No changes have been proposed to any CO_2 emitting units. Similarly, no changes have been proposed to the provisions of the permit relating to any CO_2 emitting units, which remain as set forth in the construction permit issued on January 25, 2008.

Though no response is necessary to this comment, IDEM observes that it responded to similar comments in detail in the Addendum to the Technical Support Document prepared for Significant Source Modification No. 083-23529-00003, issued on January 25, 2008 and the commenters are referred to that earlier response, although IDEM recognizes that there has been significant developments with respect to the question of the existing authority to regulate CO_2 under the Clean Air Act since that response was issued.

U.S. EPA has, in the last two years, further clarified that only pollutants subject to actual control, and not just monitoring and reporting provisions, are "pollutants subject to regulation" under the Clean Air Act. In the preamble to the U.S. EPA's proposed Green House Gas (GHG) tailoring rule, the U.S. EPA unequivocally stated "it is EPA's position that new pollutants become subject to PSD and [T]itle V when a rule controlling those pollutants is promulgated" and that "currently GHGs are not considered to be subject to regulation and have not been considered to trigger Title V applicability" 74 Fed. Reg. 55292, 55300 (October 27, 2009). The U.S. EPA's recent Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act also made clear that CO_2 is not a pollutant subject to regulation. In that finding, the U.S. EPA stated "it is EPA's current position that these Final Findings do not make well-mixed greenhouse gases 'subject to regulation' for purposes of the CAA's

[PSD] and Title V programs." 74 Fed. Reg. 66496, 66516 n. 17.

As the U.S. EPA has recognized, there is no current authority that requires actual control of CO_2 under the Clean Air Act.

Comment 5:

Natural-gas results in lower emission rates from the proposed plant. Therefore, the use of natural gas—and the resulting lower emission limits-- must be considered in a BACT determination. Natural gas fired combustion turbines are an "available" option commercial power production applications and at competitive costs, and within the meaning of 42 U.S.C. §7479(3). Both the plain language of the Clean Air Act and the legislative history behind the Act require it. The Clean Air Act requires BACT limits to be "based on the maximum degree of reduction of each pollutant… achievable for such facility through application of <u>production processes</u> and available methods, systems, and techniques, including … <u>innovative fuel combustion techniques</u>…" 42 U.S.C. § 7479(3). Clean fuels are central to this definition.

Here, natural gas not only can—but is <u>planned</u> to be burned at the combined cycle units at the Edwardsport plant. For example, on page 11 of the draft permit, IDEM describes the combined cycle units as "firing syngas, natural gas, or combined syngas and natural gas." There is also no doubt that burning cleaner natural gas would reduce air pollution: IDEM establishes lower emission limits when burning natural gas. When burning synthetic gas (i.e., from coal), CO emissions can be 0.046 lb/MMBtu, but only 0.042 lb/MMBtu when burning natural gas; particulate matter can be 0.019 lb/MMBtu when burning syn gas, but only 0.009 when burning natural gas. *See* Draft Permit page 73.

The BACT limits for the combustion turbines must be established based on cleaner natural gas fuel. Establishing BACT limits based on natural gas would not "redefine the source." BACT is applied to the "major emitting facility," rather than some different "major emitting facility." See 42 U.S.C. § 7475(a). The Clean Air Act states that "[n]o major emitting facility… may be constructed… unless… the proposed facility is subject to the best available control technology for each pollutant subjected to regulation under this chapter emitted from, or which results from, such facility…" *Id.* (emphasis added). As long as BACT is being applied to "the major emitting facility," the "redefining the source" policy is satisfied. Here, the process to generate electricity from natural gas requires same "major emitting facility" as the synthetic gas process. Not only do they both fall within the SIC Manual's "Major Group 49: Electric Services," by which a "major emitting facility" is defined, but both fuels can and will be used in the combustion turbines used to produce electricity at the Edwardsport plant.

Response 5:

This comment is not relevant to the permit since the modifications approved in the permit do not affect the combustion turbines. IDEM's BACT analysis is included as Appendix B to the Technical Support Document. Natural gas is not an alternative for the changes made by this permit.

Comment 6:

IDEM netted out the sulfur dioxide (SOx) and nitrogen oxides (NOx) emissions due to the closure of the old plant for the new plant, but these reductions will be mandated by law in a case that is currently pending and should not be used to offset the emissions for the proposed Edwardsport plant.

Response 6:

This comment is not relevant to this permitting action. This permit revision only incorporates design changes to the coal and lime material handling emission units which emit only PM/ PM_{10}/$PM_{2.5}$.

Further, IDEM does not have the power to change a permit term or condition based on pending litigation when a final adjudication has not been made. If a final adjudication is made that requires a change in a permit term or condition, the permit holder, or IDEM, will begin the process to revise the permit.

Comment 7:

Duke is claiming emissions reduction's which are relevant on a per - megawatt basis, but there are significant emission increases on a gross actual basis, the particulate matter from the new IGCC plant will increase by 124 percent, VOCs will increase by more than 600 percent and lead emissions will increase by more than 14,000 percent. With regard to the new coal lime and soda ash handling systems, there will actually be an increase in particulate matter emissions of 4.45 tons per year relative to the original draft permit.

Response 7:

The comments regarding VOC and lead emissions are not relevant to this permit. This permit revision only incorporates design changes to the coal and lime material handling emission units which emit only PM/ PM_{10}/$PM_{2.5}$. The emission calculations related to the IGCC plant are documented in the Technical Suppport Document for this permit. The new lime and soda ash storage silos and handling system have a reduced capacity and additional control devices were added to these systems. These changes are reflected in the Permit Level Determination-PSD table in the Technical Support Document, which shows a reduction in the PM/ PM_{10} emissions of 0.02 tons per year.

Comments 8:

Duke Energy is claiming that the new IGCC plant will emit less than ten (10) tons of mercury per year and under twenty-five (25) tons of aggregate hazardous air pollutants. With that claim, it would be our recommendation to IDEM to perform continuous monitoring and testing to ensure that this is true, not just a narrow snapshot of those emissions.

Response 8:

The comments regarding mercury and hazardous air pollutant emissions are not relevant to this permitting action. This permit revision only incorporates design changes to the coal and lime material handling emission units which emit only PM/ PM_{10}/$PM_{2.5}$. In any event, all monitoring and testing required by IDEM under the Part 70 rules have been incorporated into the modified operating permit. IDEM does not believe any additional monitoring or testing is necessary beyond the existing air monitoring requirements in the permit.

Comments 9:

Duke Energy said the project will produce 100 jobs, those hundred jobs are costing us what will probably turn out to be three billion dollars before the issue of global warming and carbon capture and sequestration are even addressed. The carbon capture and sequestration can add as much as 50 percent to the capital coat of the construction of the plant. The price tag was projected to be 1 billion in 2005 and when we went through the hearing before the IURC, it had increased to 1.9 billion and in my testimony in August 2007 at Bloomington hearing, I warned that we better be prepared to talk about three to four billion dollars of capital cost for this project.

At this current rate Duke Energy is projecting a 19 - 18 percent overall increase in their electric rates to build the plant. An overall increase in electric rates of 18 percent translates to about 25 percent increase in residential rates and with a billion dollars increase it will translate to 35 percent increase in residential rates. The economics of this project are raw and bad.

Response 9:

IDEM acknowledges that the commenter is concerned about the cost of the plant, the resulting utility rates and the overall economics of the project. IDEM has no authority to consider these matters when making air permitting decisions.

Comment 10:

Duke Energy mention that the IGCC is going to be the cleanest plant or one of the cleanest plants, in the world and one of the cleanest utility scale plants in the United States and so forth. If Duke Energy is talking about efficiency, this plant will not be very efficient if they do carbon capture and sequestration. Duke Energy has not made a commitment to do anything about the big global issue of climate change and global warming.

Response 10:

Carbon capture and sequestration is not required under the permit. The new IGCC plant will provide four times more electricity and will emit less pollution in comparison to the current plant. As discussed in Response 4, CO_2 is not a regulated air pollutant and this permit does not require carbon sequestration. U.S. EPA has proposed to regulate green house gas emissions, but those regulations are not in effect.

Comment 11:

There is another thing that has nothing to do with the air permit but has a significant bearing to the present issue. The issue of grey water has not been addressed by Duke. Duke Energy has no water permit application on file with IDEM at this point for this project.

Response 11:

As the commenter recognized, this comment is not relevant to this permit. Discharges of wastewater will be addressed in a National Pollution Discharge Elimination System (NPDES) permit. Duke Energy submitted an application for an NPDES permit to IDEM's Office of Water Quality on December 23, 2009. The permit application is under review by the Office of Water Quality.

Comment 12:

There have been a number of new proposed rules from IDEM on various National Ambient Air Quality standards, in at least one of those, and I think it's $PM_{2.5}$, Knox County is being considered nonattainment, or being proposed as nonattainment. What nonattainment means is that you are not meeting the current National Ambient Air Quality standards and they are health based standards.

Response 12:

Knox County has been classified as attainment for $PM_{2.5}$.

Comment 13:

In 1994, President Clinton signed an executive order requiring that environmental justice issues be dealt with across board whenever agencies are looking at projects and because IDEM is given authorization by the Federal Government to Administer the Clean Air Act in Indiana, then that executive order applies also. One of the things that you need to do in assessing this permit, whether it's a minor source or whether it's dealing with the last draft permit that you had as a major source, one of the things that IDEM should start doing with anything that happens in southwestern Indiana is looking at the issue of environmental justice in terms of carbon dioxide (CO_2,), mercury, lead and nitrogen oxides (NOx) pollution.

Response 13:

IDEM is committed to its Environmental Justice Policy, which can be viewed at http://www.in.gov/idem/files/A-008-OEA-08-P-R2.pdf on IDEM's website.

Environmental Justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, geographic location or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The Policy requires that IDEM ensure all members of the public: (1) have equal access to public information pertinent to Agency policies and procedures; (2) have adequate notice regarding all Agency program information and decision-making processes; and (3) have the opportunity to provide public comments and pertinent information to Agency program staff.

IDEM has followed this Policy throughout this permitting process. IDEM published a notice of this permitting action in the *Sun Commercial* newspaper in Vincennes. IDEM also posted a copy of the draft permit revision on its website and provided a copy to the local library. On January 27, 2010, IDEM held a public meeting and a public hearing on the draft permit at the North Knox High School Auditorium in Bicknell, Indiana, for citizens and interested parties to discuss questions and concerns related to the project.

Comments regarding CO_2, mercury, lead and NOx pollution are not relevant to this permitting action. This permit revision incorporates design changes to the coal and lime material handling emission units which emit only PM/ PM_{10}/$PM_{2.5}$.

Comment 14:

In Evansville, the kids are five times more likely to be hospitalized with asthma than a kid of the same age and gender in Fort Wayne because they get exposed to serious levels of toxic emissions. Twenty (20) percent of kids in Evansville have to carry, or have their nurses carry, because they aren't allowed to carry them in the school, little nebulizers that treat people for asthma. To build additional power facilities in this area is pretty well giving people, if not a death sentence, it's subjecting them to life of illness, of ugliness and any number of deleterious things that come along with power plant construction.

Response 14:

The commenter has not cited any study, authority or other source for the juvenile asthma rates in Evansville and Ft. Wayne. The commenter does not cite to any study that concludes that there is a direct relationship between the asthma rates in these two cities and the levels of air pollution in those cities. The permits for the Edwardsport IGCC plant are protective of human health and the environment and will result in a reduction of thousands of tons of regulated pollutants, including a reduction in all hazardous air pollutants.

Comment 15:

I am a member of the Green Sanctuary Task Force of the Unitarian Universalist Church of Bloomington, Indiana. Our task force is part of an interfaith coalition concerned about global climate change. Our task force testified before the Indiana Utilities Regulatory Commission in opposition to the Edwardsport plant. We also opposed its air quality permit when the request came before IDEM.

The specific issue before IDEM in the current petition is the emission of particulate matter. But the larger issue is greenhouse gas emissions. Even the plant's advocates now admit that the ground under the plant may not be suitable for massive carbon dioxide storage. Thus, at cost of energy, the CO_2 waste must be shipped hundreds of miles for putative use in oil recovery. And only a fraction of CO_2 emissions at Edwardsport will be sequestered. In the meantime, the great majority of carbon dioxide emissions will escape into the atmosphere.

Response 15:

As discussed in Response 4, CO_2 is not a regulated pollutant and this permit does not require carbon sequestration.

Comment 16:

I have received notice about a comment period relevant to Duke Energy's modification to a permit to build a coal plan in Edwardsport. I question the wisdom of building another coal plant. There are other options that should be considered--wind, gas and other technology is evolving. My concern is that the waste produced by coal plants is actually more radioactive than that generated by their nuclear counterparts--100 times fore than a nuclear power plant producing the same amount of energy. When coal is burned into fly ash, uranium and thorium are concentrated up to 10 times their original levels. These are both radioactive elements. People living near a coal-producing plant absorb higher doses than people living near nuclear facilities. When food is grown in the area, doses are 50 to 200% higher. Other products of coal power, acid rain-producing sulfur dioxide and smog-forming nitrous oxide pose greater health risks than radiation. In 1985, the U.S. spent $2.4 billion (in 1990 $$s); in 1990, the U.S. spent $3.6 billion (in 1990 $$s).

Duke Energy will be adding pollutants to the air in Northern Indiana. Duke Energy will have to be responsible for at least a portion of the cost of asthma treatment for patients in the northern part of Indiana. It just is not fair for Duke to profit from the plan, and stick Indiana for the cost of the sickness the pollutants bring about.

Response 16:

IDEM, OAQ has no legal authority to consider or address issues such as other means of generating electricity in its permit determinations.

The commenter has not cited any study, authority or other source supporting its comments on the radioactivity of waste produced by coal-fired power plants. OAQ has no authority under state law or rules to regulate coal ash waste, uranium and thorium in an air permit. The federal Clean Air Act does not regulate coal ash waste, uranium and thorium. Waste issues and requirements may be addressed in other laws and regulations. The gasification process to be utilized by the IGCC plant does not combust coal nor does it produce fly ash as in a conventional pulverized coal plant.

The IGCC plant will be regulated under the Clean Air Act's Acid Rain Program. The IGCC plant will reduce the total amount of nitrogen oxides and significantly reduce the total amount of sulfur dioxide emitted relative to the existing Edwardsport Generating Station.

Comment 17:

In December 2009, the State Utility Forecasting Group (SUFG), the entity responsible for providing information to the Indiana Utility Regulatory Commission, released their 2009 forecast of electricity demand and resources for Indiana. In this report, the SUFG highlights the approval and construction of the Edwardsport Integrated Gasification Combined Cycle (IGCC) plants.

The majority of Indiana's electricity - over 95% - comes from coal. It's critical that our energy suppliers find a way to use this abundant, native resource in a way that provides for environmental sustainability. The use of the IGCC technology does that, by providing lower air emissions, less water use and more efficient ways of producing electricity than a conventional coal-fired power plant.

The Indiana Chamber of Commerce believes that the Edwardsport plant, when combined with energy efficiency programs and renewable energy resources, is a step in the right direction to lowering the carbon intensity of our energy supply. For the benefit of all Hoosiers, we urge the Indiana Department of Environmental Management to issue the permit revision and source modification to allow the operation of the Edwardsport plant.

Response 17:

IDEM acknowledges that these comments are important to the commenter. However, these comments do not have any direct impact on how IDEM reviews and make decisions on air permit applications.

Comment 18:

The advantages of building this type of plant, are lower air emissions, less water use, less coal waste and more efficient electricity production than a conventional coal - fired power plant.

The majority of our state's electric power comes from coal. It's urgent that we find ways to burn it cleanly. The Edwardsport coal gasification plant is important to our state's energy future because it offers an opportunity to use an abundant, local and comparatively low-cost fuel, Indiana coal. Additionally, the IGCC plant will be so efficient to removing sulfur from the gasified coal that it would be feasible to produce a useable agricultural product from the extracted sulfur.

When the plant begins operation in 2012, Duke Energy, Indiana will have a work force of about 100, with an estimated annual payroll of seven to nine million dollars annually. That means new spending power for the state and local economy, and obviously an increased tax base. All of these things are as true today as they were two years ago.

Duke Energy, Indiana believes the IGCC plant, in conjunction with other clean energy options and energy efficiency programs in the works, will be a major part of the bridge to building a low-carbon energy future.

The permit modification being discussed tonight is simply an evolution in the design of the coal - handling and water treatment material storage facilities, including additional particulate emission controls, and will not result in any increase in emissions.

In conclusion, I support the permit modification IDEM has proposed and believe approval for this modification will produce a facility that will improve the environment of Indiana and help construct a power plant that will set the standard for environmental performance in the future.

Response 18:

IDEM acknowledges that these comments are important to the commenter. However, these comments do not have any direct impact on how IDEM reviews and make decisions on air permit applications.

Comment 19:

The monitoring for the sources covered in the pending draft revised permits is inadequate. To ensure compliance with particulate matter limits, the draft permit would only require testing once every five years. Judge McKinney found in the recent Cinergy remedy trial decision in the Southern District of Indiana that periodic stack testing -- in that case even more often than the once-per-five-years here -- was insufficient to ensure continuous compliance. The material handling and other emission sources in this case vary in operating rate, emissions, and properties of material handled (i.e. moisture content, silt content, composition, etc.). An emission test would not be representative of all operating conditions during a single day, much less all conditions during the 1826 days between emission tests in the draft permit.

Response 19:

IDEM does not believe any additional monitoring or testing is necessary beyond the existing air monitoring requirements in the permit nor has the commenter provided information relative to the units included in this modification that would indicate monitoring more frequently than that provided for in IDEM's rule (and incorporated into the modification) is warranted. Further, IDEM does not have the power to change a permit term or condition based on pending litigation when a final adjudication has not been made. If a final adjudication is made that requires a change in a permit term or condition, the permit holder, or IDEM, will begin the process to revise the permit.

Comment 20:

The Sierra Club previously submitted comments on the renewal of the Title V permit for the Edwardsport station; however, IDEM has not yet responded to those comments prior to this modification being open for public comment. Nothing in the pending draft permit revision cures the problems identified by the comments submitted on the renewal permit. We are resubmitting our prior comments [on the renewal of the Title V permit] and incorporating them here. Moreover, one of the permits that IDEM proposes to be revising through this pending modification is an expired Title V permit. Based on these facts, IDEM has unnecessarily complicated this permitting process. Comments previously submitted on the renewal of the Title V permit are being resubmitted and incorporated into comments on this modification.

Response 20:

IDEM acknowledges that that there has been overlap in the public notice phases portions of the separate proceedings for the renewal of the Part 70 operating permit for the Edwardsport station (No. T083-27138-00003) and the proposed modification (No. 083-28683-00003 and 083-28801-00003) affecting the source and permit. IDEM was in the process of issuing the renewal permit, having already closed the public comment period on that proposed permit, when it received the application for the modification that is the subject of this action on November 23, 2009. IDEM explained the interaction between these permitting actions in the Technical Support Document to allay confusion regarding the overlap, stating: "Concurrently with this permit review proceeding for proposed PSD/Significant Source Modification No. SSM 083-28638-00003 and proposed Significant Permit Modification No. SPM 083-28801-00003, IDEM's OAQ is also concluding its processing of an application for renewal of the existing Part 70 Operating Permit for the Edwardsport Generating Station, Part 70 Permit renewal No. 083-27138-00003, which will be likely to make revisions to the existing Part 70 permit that are independent of those that are proposed under this permit review proceeding." TSD, page 5 of 19.

Despite the unusual timing of the two permitting actions, IDEM is committed to ensuring that each complies with the applicable public notice provisions and that the agency fully responds to the comments received in the two actions. To the extent that a resubmitted (renewal) comment from the permit renewal proceeding is also applicable to the source and permit modification that are the subject of the current permitting action, the comments have been addressed above. However, as the proposed modifications affect only Section D.10 and the corresponding descriptive terms of Sections A.2, G.3 and G.4 of such permits, as described in the "Description of the Modification" contained in the Technical Support Document (page 4 of 19), authorizing only the construction and operation of the coal handling equipment and lime/soda ash handling equipment, resubmitted renewal comments that are not applicable to those portions of the permits revised in the modifications will be addressed in IDEM's response to comments for the renewal (No.T083-27138-00003).

Specifically, IDEM is withholding substantive comment on the "Petition to Intervene" originally filed with respect to the renewal of the Edwardsport Part 70 Operating Permit (No.T083-27138-00003), which the commenter proposed to resubmit by reference as comments to the modifications. Without further discussion as to the merits of the Petition to Intervene, IDEM notes that the Petition to Intervene is expressly captioned solely with respect to the Part 70 renewal proceeding (No. 083-27138-00003). It is not a petition to intervene that has been specifically and expressly captioned and filed in this modification proceeding, as IDEM might expect a petition submitted in accordance with Ind. Code 13-30-1 *et seq.* to be. It is IDEM's position that a petition to intervene is specific to the particular permitting action for which it is filed. Because of this, IDEM does not acknowledge that the Permit to Intervene applies with respect to the proposed modifications and views the inclusion of the Petition to Intervene with commenter's comments as being merely informational of what was filed in the renewal proceeding. IDEM will respond to the Petition to Intervene in the matter in which it was filed – the proposed renewal of the Edwardsport Title V Operating Permit (No.T083-27138-00003). IDEM intends to complete the permitting process for the renewal as expeditiously as possible following the completion of the instant permitting action.

Finally, IDEM notes that, pursuant to 326 IAC 2-7-4(a)(1)(D), upon receiving a timely and complete renewal application, if IDEM fails to issue or deny the permit renewal prior to the expiration date of an existing this Part 70 permit, as modified, the existing permit shall not expire and its 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. IDEM received the renewal application for the Part 70 permit for the Edwardsport station on November 13, 2008.

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a PSD/Part 70 **Significant Source** Modification.

Source Description and Location

Source Name:	**Duke Energy Indiana - Edwardsport Generating Station**
Source Location:	**15424 East State Rd 358, Edwardsport, IN 47258**
County:	**Knox**
SIC Code:	**4911**
Operation Permit No.:	**T 083-7243-00003**
Operation Permit Issuance Date:	**August 10, 2004**
PSD/Significant Source Modification No.:	**SSM 083-28683-00003**
Significant Permit Modification No.:	**SPM 083-28801-00003**
Permit Reviewer:	**Josiah Balogun**

Existing Approvals

The source was issued Part 70 Operating Permit No. T 083-7243-00003 on August 10, 2004. The source has since received the following approvals:

(a) First Significant Permit Modification – NOx Budget Permit No. 083-17006-00003, issued on June 7, 2006;

(b) Acid Rain Permit Renewal No. 083-19349-00003, issued on July 17, 2006;

(c) Acid Rain – Phase 2 NOx Permit No. 083-24145-00003, issued on July 9, 2007;

(d) Second Significant Permit Modification No. 083-23531-00003, issued March 11, 2008; and

(e) Third Significant Permit Modification – CAIR Permit No. 083-25679-00003, issued June 24, 2008.

The source is located in Knox County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment as of June 15, 2004, for the 8-hour ozone standard.[1]
PM_{10}	Unclassifiable effective November 15, 1990.[2]
NO_2	Cannot be classified or better than national standards.
Pb	Not designated.

[1]Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005.
[2] Unclassifiable or attainment effective April 5, 2005, for $PM_{2.5}$.

(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides (NOx) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NOx emissions are

considered when evaluating the rule applicability relating to ozone. Knox County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2. This modification does not include emissions of VOC and NOx.

(b) $PM_{2.5}$
Knox County has been classified as attainment for $PM_{2.5}$. On May 8, 2008 U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for $PM_{2.5}$ emissions, and the effective date of these rules was July 15th, 2008. Indiana has three years from the publication of these rules to revise its PSD rules, 326 IAC 2-2, to include those requirements. The May 8, 2008 rule revisions allow IDEM to regulate PM_{10} emissions as a surrogate for $PM_{2.5}$ emissions until 326 IAC 2-2 is revised.

(c) Other Criteria Pollutants
Knox County has been classified as attainment or unclassifiable in Indiana for SO_2, CO, PM_{10}, NO_2, and Pb. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(d) Since this source is classified as a fossil fuel fired steam electric plant of more than two hundred fifty million (250,000,000) British thermal units per hour heat input, it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(gg)(1).

(e) Since this source is classified as a fossil fuel fired steam electric plant of more than two hundred fifty million (250,000,000) British thermal units per hour heat input, it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(gg)(1).

(f) Fugitive Emissions
Since this type of operation is in one of the twenty-eight (28) listed source categories under 326 IAC 2-2, fugitive emissions are counted toward the determination of PSD applicability.

Source Status

The table below summarizes the potential to emit of the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

Pollutant	tons/year
PM >	100
PM_{10} >	100
SO_2 >	100
VOC >	100
CO >	100
NOx >	100

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a regulated pollutant is emitted at a rate of 100 tons per year or more, and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(gg)(1).

(b) These emissions are based upon Title V operating Permit No.T083-7243-00003, issued on August 10, 2004.

The table below summarizes the potential to emit HAPs for the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

HAPs	tons/year
Single HAP	> 10
Total HAPs	> 25

This existing source is a major source of HAPs, as defined in 40 CFR 63.41, because HAP emissions are greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA). However, the proposed IGCC plant will be a minor source of HAPs upon retirement of the existing generating units and startup of the IGCC plant. Therefore, the IGCC plant will be a minor source under Section 112 of the CAA.

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed a modification application, submitted by Duke Energy Indiana - Edwardsport Generating Station on November 23, 2009. On March 11, 2008, the Office of Air Quality (OAQ) issued a permit (Permit No. SSM 083-23529-00003) to Duke Energy Indiana to construct and operate an Integrated Gasification and Combined Cycle (IGCC) electric generating plant at the Edwardsport generating station site. The IGCC plant would replace the existing electric generating equipment at the Edwardsport Generating Station. During construction planning for the material handling (coal and lime) facilities, Duke identified certain necessary design changes which require the installation of additional emitting equipment. Accordingly, this application constitutes a request for a PSD permit revision to address certain revisions and additions to the coal and lime material handling emission units of the proposed IGCC plant at the Edwardsport generating facility. Since this request presents design changes to facilities and operations previously reviewed and permitted by IDEM under the PSD rules these changes will be considered part of the original project and addressed in a revision to the previously issued PSD permit in 2008. The additional and revised equipments that are the subject of this source modification will emit only PM/PM10/PM2.5. No other regulated pollutants will be emitted by the equipment to be added or revised under the source modification. The following are the lists of the modified emission unit(s) and pollution control device(s):

(1) The following equipment for the coal handling system:

(A) 1200 ton per hour enclosed coal conveyor with particulate emissions from drop point to active coal pile stacking tube controlled by an insertable dust filter, exhausting to Stack S-1D.

(B) One (1) 1800 ton per hour reclaim tunnel, using two (2) 900 ton per hour conveyors with enclosed drop points and particulate matter controlled by a baghouse and exhausting to Stack S-2A.

(C) Two (2) 900 ton per hour enclosed coal conveyors with particulate matter from enclosed drop points controlled by insertable dust filters and exhausting to Stacks S-2B and S-2C.

(D) Two (2) enclosed coal bunkers with a total loading capacity of 1800 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-3A and S-3B.

(2) Lime and soda ash handling system, to be permitted in 2010:

(A) Transfer of lime from truck or railcar by a closed pneumatic conveyor to two (2) lime storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4A and S-4B.

(B) Transfer of soda ash from truck or railcar by a closed pneumatic conveyor to two (2) soda ash storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4C and S-4D.

The sole purpose of proposed PSD/Significant Source Modification No. SSM 083-28638-00003 and proposed PSD/Significant Permit Modification No. 083-28801-00003 is to authorize construction and operation of the coal handling equipment and lime/soda ash handling equipment described above as a part of Duke Energy Indiana's Edwardsport IGCC Station. Such authorizing provisions appear only in Section D.10 and the corresponding descriptive terms of Sections A.2, G.3 and G.4 of such permits.

Enforcement Issues

There are no pending enforcement actions related to this modification.

Permit Level Determination – Part 70

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

The following table is used to determine the appropriate permit level under 326 IAC 2-7-10.5. This table reflects the PTE before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

Pollutant	Potential To Emit (tons/year)
PM 3648.1	
PM10 3648.1	
SO_2 0	
VOC 0	
CO 0	
NOx 0	

The uncontrolled emissions of PM and PM10 are greater than 25 tons per year and therefore require a significant source modification under 326 IAC 2-7-10.5(f).The modification includes a reevaluation of PSD BACT for PM/PM10/PM2.5. Therefore, this source modification shall be processed as PSD/Significant Source Modification pursuant to 326 IAC 2-7-10.5(f)(1) and (4). Additionally, the modification will be incorporated into the Part 70 Operating Permit through a significant permit modification issued pursuant to 326 IAC 2-7-12(d), because modifying the existing operating conditions of the coal and lime material handling facilities in the Part 70 Operating Permit requires a case-by-case determination of an emission limitation in a Part 70 Operating Permit.

The only changes to the existing Part 70 Operating Permit for Duke Energy Indiana's Edwardsport Generating Station that would occur as a result of proposed PSD/Significant Source Modification

No. SSM 083-28638-00003 and proposed Significant Permit Modification No. SPM 083-28801-00003, if approved and issued, are limited in scope to those provisions of Section D.10 and corresponding provisions of Section A.2 of such proposed permits that address the coal handling equipment and lime/soda ash handling equipment described above under the heading "Description of Proposed Modification". Also, descriptive changes similar to those in Section A.2 would be added to Sections G.3 and G.4 of the permit.

Concurrently with this permit review proceeding for proposed PSD/Significant Source Modification No. SSM 083-28638-00003 and proposed Significant Permit Modification No. SPM 083-28801-00003, IDEM's OAQ is also concluding its processing of an application for renewal of the existing Part 70 Operating Permit for the Edwardsport Generating Station, Part 70 Permit renewal No. 083-27138-00003, which will be likely to make revisions to the existing Part 70 permit that are independent of those that are proposed under this permit review proceeding.

Permit Level Determination – PSD

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of this Part 70 permit modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

	Potential to Emit (Tons per year)						
System	**Emission Unit**	**PM**	**PM10**	**SO_2**	**VOC**	**CO**	**NO_X**
Coal Material Handling	Reclaim Tunnel (S-2A)	2.88	2.88	0	0	0	0
	Conveyor MH-002 Head Chute (S-1D)	0.23 0.23		0	0	0	0
	Conveyor MH-003A Head Chute (S-2B)	0.23 0.23		0	0 0		0
	Conveyor MH-003B Head Chute (S-2C)	0.23 0.23		0	0	0	0
	Coal Bunker #1 (S-3A)	0.28	0.28	0	0	0	0
	Coal Bunker #2 (S-3B)	0.28	0.28	0	0	0	0
Makeup Water System Material Handling	Lime Silo #1 (S-4A)	0.08	0.08	0	0	0	0
	Lime Silo #2 (S-4D)	0.08	0.08	0	0	0	0
	Soda Ash Silo #1 (S-4C)	0.08	0.08	0	0	0	0
	Soda Ash Silo #2 (S-4D)	0.08	0.08	0	0	0	0
Total for Modification		4.45	4.45	0	0	0	0
Total Emission allowed for these emission units before this modification	4.47		4.47	0	0	0	0
Total for Modification		- 0.02	- 0.02	0	0	0	0
PSD Significant Level	25		15	40	40	100	40

Although there are no overall emissions increases of PM/PM_{10} to result from the proposed modification, the modification affects PM/PM_{10} emissions of individual units of the existing major stationary source that is under construction and, therefore, this modification is considered to be part of the 2008 PSD modification. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do apply.

Federal Rule Applicability Determination

The following federal rules are applicable to the source due to this modification:

(a) 40 CFR 60, Subpart Y - Standards of Performance for Coal Preparation Plants which process more than 181 Mg (200 tons) per day. This includes the following facilities: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems.

326 IAC 12, 40 CFR 60, Subpart Y is applicable to the following units:

(A) Coal receiving and handling system using enclosed conveyors consisting of the following equipments:

(1) Coal receiving and handling system, to be permitted in 2010, except the truck or railcar receiving and unloading station permitted in 2008, using enclosed conveyors consisting of the following equipment:

(A) 1200 ton per hour enclosed coal conveyor with particulate emissions from drop point to active coal pile stacking tube controlled by an insertable dust filter, exhausting to Stack S-1D.

(B) One (1) 1800 ton per hour reclaim tunnel, using two (2) 900 ton per hour conveyors with enclosed drop points and particulate matter controlled by a baghouse and exhausting to Stack S-2A.

(C) Two (2) 900 ton per hour enclosed coal conveyors with particulate matter from enclosed drop points controlled by insertable dust filters and exhausting to Stacks S-2B and S-2C.

(D) Two (2) enclosed coal bunkers with a total loading capacity of 1800 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-3A and S-3B.

The coal preparation plant is subject to the following portions of Subpart Y.

- 40 CFR 60.250
- 40 CFR 60.251
- 40 CFR 60.252(c)
- 40 CFR 60.254(b)(2)

(b) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) applicable to this proposed modification.

(c) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to new or modified emission units that involve a pollutant-specific emission unit and meet the following criteria:

(1) has a potential to emit before controls equal to or greater than the major source threshold for the pollutant involved;

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

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.2, to each new or modified emission unit involved:

Emission Unit	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)
Reclaim Tunnel (S-2A) PM10	Baghouse	Y	2883.29	2.88	100	Y	N
Reclaim Tunnel (S-2A) PM	Baghouse	Y	2883.29	2.88	100	Y	N
Conveyor MH-002 Head Chute (S-1D) PM10	Insertable Dust Filter	Y	225.26 0.23		100	Y	N
Conveyor MH-002 Head Chute (S-1D) PM	Insertable Dust Filter	Y	225.26 0.23		100	Y	N
Conveyor MH-003A Head Chute (S-2B) PM10	Insertable Dust Filter	Y	225.26 0.23		100	Y	N
Conveyor MH-003A Head Chute (S-2B) PM	Insertable Dust Filter	Y	225.26 0.23		100	Y	N
Conveyor MH-003B Head Chute (S-2C) PM10	Insertable Dust Filter	Y	225.26 0.23		100	Y	N
Conveyor MH-003B Head Chute (S-2C) PM	Insertable Dust Filter	Y	225.26 0.23		100	Y	N
Coal Bunker #1 (S-3A) PM10	Bin Vent Dust Collector	Y	28.16 0.28		100	N	N
Coal Bunker #2 (S-3B)	Bin Vent Dust Collector	Y	28.16 0.28		100	N	N
Lime Silo #1 (S-4A)	Bin Vent Dust Collector	Y	8.17 0.08		100	N	N
Lime Silo #2 (S-4D)	Bin Vent Dust Collector	Y	8.17 0.08		100	N	N
Soda Ash Silo #1 (S-4C)	Bin Vent Dust Collector	Y	8.17 0.08		100	N	N
Soda Ash Silo #2 (S-4D)	Bin Vent Dust Collector	Y 8.17		0.08	100	N	N

New Source Performance Standard 40 CFR 60 Subpart Y was revised in Federal Regster Vol.74,No. 194 on Thursday, October 8, 2009. Pursuant to 40 CFR 64.2(b), Exemptions to Compliance Assurance Monitoring (CAM), new source performance standards proposed after November 15, 1990 are exempt from the requirements of CAM. Therefore, the emission units in this modification are exempt from CAM.

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are not applicable to Reclaim Tunnel, Conveyor MH-002 Head Chute, Conveyor MH-003A Head Chute and Conveyor MH-003B Head Chute (S-2C) for PM/PM10 as part of this Part 70 permit.

State Rule Applicability Determination

326 IAC 2-2 (PSD)
PSD applicability is discussed under the Permit Level Determination - PSD section.

326 IAC 2-2-3 (PSD BACT: Control Technology Review Requirements)
Pursuant to 326 IAC 2-2-3, the Best Available Contol Technology (PSD BACT) for coal receiving and unloading station emissions exhausting to Stack S- 1B, coal reclaim tunnel conveyor emissions exhausting to stack S-2A, coal conveyor emissions exhausting to Stacks S-1D, S-2B and S-2C, coal bunker emissions exhausting to Stacks S-3A and S-3B, and lime handling emissions exhausting to Stacks S-4A and S-4B and Soda Ash handling emissions exhausting to Stacks S-4C and S-4D shall be as follows:

(1) Best management practices.

(2) PM emissions from the high efficiency baghouse, insertable dust filters and bin vent dust collectors shall not exceed a grain loading of 0.003 grains per dry standard cubic foot (gr/dscf).

(A) 0.66 lbs/hr for the reclaim tunnel baghouse (Stack S-2A);

(B) 0.064 lb/hr for the bin vent dust collector associated the coal bunker, identified as coal bunker #1 (Stack S-3A);

(C) 0.064 lb/hr for the bin vent dust collector associated the coal bunker, identified as coal bunker #2 (Stack S-3B);

(D) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-002 Head Chute (Stack S-1D);

(E) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-003A Head Chute (Stack S-2B);

(F) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-003B Head Chute (Stack S-2C);

(G) 0.019 lb/hr for the bin vent dust collector associated with the lime silo, identified as Lime Silo #1(Stack S-4A);

(H) 0.019 lb/hr for the bin vent dust collector associated with the lime silo, identified as Lime Silo #2 (Stack S-4B);

(I) 0.019 lb/hr for the bin vent dust collector associated with the soda ash silo #1 (Stack S-4C); and

(J) 0.019 lb/hr for the bin vent dust collector associated with the soda ash silo #2 (Stack S-4D).

326 IAC 2-2-4 (Air Quality Analysis Requirements)
Section (4)(a) of this rule, requires that the PSD application shall contain an analysis of ambient air quality in the area that the major stationary source would affect for pollutants that are emitted at major levels or significant amount. Duke Energy Indiana - Edwardsport Generating Station has submitted an air quality analysis, which has been evaluated by the Technical Support and Modeling Section. Included in that analysis were changes to the PM_{10} emissions sources

associated with certain material handling operations, as well as changes to certain building, structure and source locations at the IGCC plant. The analysis demonstrated that these changes would not alter or affect the outcome of the air quality impact evaluation performed in support of the PSD construction permit issued for the IGCC plant in early 2008. Emissions of CO, PM_{10}, SO_2, and NO_x were shown to have no adverse impact on human health or welfare, since predicted concentrations were below the corresponding NAAQS. NAAQS modeling was performed under the PSD provisions for emissions of PM_{10} and CO and on a voluntary basis by the applicant for emissions of SO_2 and NO_x.

326 IAC 2-2-5 (Air Quality Impact Requirements)
326 IAC 2-2-5(e)(1) of this rule, requires that the air quality impact analysis required by this section shall be conducted in accordance with the following provisions:

(1) Any estimates of ambient air concentrations used in the demonstration processes required by this section shall be based upon the applicable air quality models, data bases, and other requirements specified in 40 CFR Part 51, Appendix W (Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Guideline on Air Quality Models).

(2) Where an air quality impact model specified in the guidelines cited in subdivision (1) is inappropriate, a model may be modified or another model substituted provided that all applicable guidelines are satisfied.

(3) Modifications or substitution of any model may only be done in accordance with guideline documents and with written approval from U.S. EPA and shall be subject to public comment procedures set forth in 326 IAC 2-1.1-6.

NAAQS modeling for the appropriate time-averaging periods for PM_{10}, CO, SO_2, and NO_x was conducted and compared to the respective NAAQS limits. All maximum-modeled concentrations were compared to the respective NAAQS limits. All maximum-modeled concentrations during the five years were below the NAAQS limits and further modeling was not required. Similarly, the PSD increment analysis conducted for PM_{10} showed that pollutant impacts for all averaging periods were below 80% of the respective available increments. NAAQS modeling was performed under the PSD provisions for emissions of PM_{10} and CO and on a voluntary basis by the applicant for emissions of SO_2 and NO_x.

326 IAC 2-2-7 (Additional Analysis, Requirements)
326 IAC 2-2-7(a) requires an analysis of the impairment to visibility, soils and vegetation that would result from emissions from the proposed source. This analysis is to include the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the source.

The results of the additional impact analysis conclude the operation of the IGCC facility, with the changes proposed in the pending source modification request, will have no significant impact on economic growth, soils or vegetation in the immediate vicinity or on any Class I area. CO is not a pollutant that affects visibility. The visibility analysis was not necessary for this application.

Economic Growth
The purpose of the growth analysis is to quantify projected commercial and residential growth associated with the proposed project and to estimate the air quality impacts from this growth either quantitatively or qualitatively.

The addition of the IGCC plant at the Edwardsport facility should not result in any noticeable residential growth in the area. Commercial growth is anticipated to occur at a gradual rate in the future. However, this growth will not be directly associated with the proposed IGCC project. Since the area is predominately rural, it is not expected the growth impacts will cause a violation of the NAAQS or the PSD increment.

Soils and Vegetation Analysis
A list of soil types present in the general area was determined. Soil types include the following: Sandy and Loamy Lacustrine deposits and Eolian sand, Alluvial and Outwash deposits.

Due to the agricultural nature of the land, crops in the Knox County area consist mainly of corn, sorghum, wheat, soybeans, and oats (2002 Agricultural Census for Knox County). The maximum modeled concentrations for Duke Energy's IGCC plant, including the proposed changes, are well below the threshold limits necessary to have adverse impacts on the surrounding vegetation such as autumn bent, nimblewill, barnyard grass, bishopscap and horsetail, and milkweed (Flora of Indiana – Charles Deam). Livestock in Knox County consist mainly of hogs, cattle, and sheep (2002 Agricultural Census for Knox County) and will not be adversely impacted from the facility. Trees in the area are mainly hardwoods. These are hardy trees and no significant adverse impacts are expected due to modeled concentrations.

Federal and State Endangered Species Analysis
Federal and state endangered or threatened species are listed by the U.S. Fish and Wildlife Service; Division of Endangered Species for Indiana and includes 5 amphibians, 27 birds, 10 fishes, 7 mammals, 15 mollusks, and 15 reptiles. Of the federal and state endangered species on the list, 2 amphibians, 7 reptiles, 16 mollusks, 7 fish, 18 birds, and 4 mammals have habitat within Knox County. The mollusks, fish, amphibians and certain species of birds and mammals are found along rivers and lakes while the other species of birds and mammals are found in forested areas. The facility site is located on existing industrial and former agricultural properties and is not expected to have any additional adverse effects on the habitats of the species than what has already occurred from the industrial, farming, and residential activities in the area.

Federal and state endangered or threatened plants are listed by the U.S. Fish and Wildlife Service, Division of Endangered Species for Indiana. They list 22 state significant species of plants. At this time no federally endangered plant species are found in Knox County. The endangered plants do not thrive in industrialized and residential areas. The facility is not expected to adversely affect any plant on the endangered species list.

326 IAC 2-2-7 (Additional Analysis, Requirements)
326 IAC 2-2-7(a) requires an analysis of the impairment to visibility, soils and vegetation. An analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the source.

The results of the additional impact analysis conclude the operation of the facility will have no significant impact on economic growth, soils or vegetation in the immediate vicinity or on any Class I area. CO is not a pollutant that affects visibility. The additional impacts analysis concluded, consistent with the original air quality impact analysis for the IGCC plant, that potential visibility impacts of plant operation on the nearest Class I area (Mammoth Cave National Park) would be insignificant.

326 IAC 2-2-10 (Source Information)
The Permittee has submitted all information necessary to perform the analysis or make the determination required under this rule.

326 IAC 2-2-12 (Permit Rescission)
The permit issued under this rule shall remain in effect unless and until it is rescinded, modified, revoked, or it expires in accordance with 326 IAC 2-1.1-9.5 or section 8 of this rule.

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.

Testing Requirements

(a) Testing

Emission units	Control device	When to test	Pollutants	Frequency of testing
Reclaim Tunnel (Stack S-2A).	Baghouse	60 days / no later than 180 days	PM/PM10	Every five (5) years
Conveying Operations (Stacks S-1D, S-2B and S-2C).	Insertable Dust Collector	60 days / no later than 180 days	PM/PM10	Every five (5) years
Coal Bunkers (Stacks S-3A and S-3B)	Bin vent dust collector	60 days / no later than 180 days	PM/PM10	Every five (5) years
Lime Silos and Soda Ash Storage, (Stacks S-4A, S-4B, S-4C and S-4D)	Bin vent dust collector	60 days / no later than 180 days	PM/PM10	Every five (5) years

The compliance monitoring requirements applicable to this source are as follows:

Control	Parameter	Frequency	Range	Excursions and Exceedances
Reclaim Tunnel (baghouse, Stack S-2A).	Water Pressure Drop	Daily	3 to 6 inches	Response Steps
	Visible Emissions		Normal-Abnormal	
Conveyors (Insertable Dust Collector, Stacks S-1D, S-3B and S-2C).	Water Pressure Drop	Daily	3 to 6 inches	Response Steps
	Visible Emissions		Normal-Abnormal	
Coal Bunkers, Lime Silos and Soda Ash Storage, (Bin vent dust collector Stack S-3A, S-3B, S-4A, S-4B, S-4C and S-4D)	Water Pressure Drop	Daily	3 to 6 inches	Response Steps
	Visible Emissions		Normal-Abnormal	

Proposed Changes

The changes listed below have been made to Part 70 Operating Permit No.T083-7243-00003. Deleted language appears as ~~strikethroughs~~ and new language appears in **bold**:

Change 1: The source has proposed various changes to Section A.2 and D.10 due to design changes in the coal and other material handling equipment.

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:

....

(B) Integrated Gasification and Combined Cycle (IGCC) Electric Generating Plant:

....

(c) Material handling operations consisting of:

(1) Coal receiving and handling system, **to be permitted in 2010, except the truck or railcar receiving and unloading station** permitted in 2008, using enclosed conveyors consisting of the following equipment:

(A) ~~250 ton per hour coal pile drop point particulate emissions controlled by a baghouse, exhausting to Stack S-1D~~. **1200 ton per hour enclosed coal conveyor with particulate emissions from drop point to active coal pile stacking tube controlled by an insertable dust filter, exhausting to Stack S-1D.**

(B) One (1) 1200 ton per hour truck or railcar receiving and unloading station with enclosed drop points and particulate emissions controlled by a baghouse and exhausting to Stack S-1B.

(C) ~~Two (2) enclosed 250 ton per hour coal grinding mills with particulate emissions controlled by a baghouse and exhausting to Stack S-1A~~. **One (1) 1,800 ton per hour reclaim tunnel, using two (2) 900 ton per hour conveyors with enclosed drop points and particulate matter controlled by a baghouse and exhausting to Stack S-2A.**

(D) Two (2) 900 ton per hour enclosed coal conveyors with particulate matter from enclosed drop points controlled by insertable dust filters and exhausting to Stacks S-2B and S-2C.

(E) Two (2) enclosed coal bunkers with a total loading capacity of 1800 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S- 3A and S-3B.

~~(2) Lime handling system, permitted in 2008~~

~~(A) Transfer of lime from truck or railcar by a closed pneumatic conveyor to lime storage silo.~~

~~(B) One (1) 300 ton per hour lime storage silo with particulate emissions controlled by a baghouse and exhausting to Stack S-1C.~~

(2) Lime and soda ash handling system, to be permitted in 2010:

(A) Transfer of lime from truck or railcar by a closed pneumatic conveyor to two (2) lime storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4A and S-4B.

(B) Transfer of soda ash from truck or railcar by a closed pneumatic conveyor to two (2) soda ash storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4C and S- 4D.

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Material handling operations consisting of:

(1) ~~Coal receiving and handling system using enclosed conveyors consisting of the following equipment~~: **Coal receiving and handling system, to be permitted in 2010, except the truck or railcar receiving and unloading station permitted in 2008, using enclosed conveyors consisting of the following equipment:**

(A) ~~250 ton per hour coal pile drop point particulate emissions controlled by a baghouse, exhausting to Stack S-1D.~~ **1200 ton per hour enclosed coal conveyor with particulate emissions from drop point to active coal pile stacking tube controlled by an insertable dust filter, exhausting to Stack S-1D.**

(B) One (1) 1200 ton per hour truck or railcar receiving and unloading station with enclosed drop points and particulate emissions controlled by a baghouse and exhausting to Stack S-1B.

(C) ~~Two (2) enclosed 250 ton per hour coal grinding mills with particulate emissions controlled by a baghouse and exhausting to Stack S-1A.~~ **One (1) 1,800 ton per hour reclaim tunnel, using two (2) 900 ton per hour conveyors with enclosed drop points and particulate matter controlled by a baghouse and exhausting to Stack S-2A.**

(D) Two (2) 900 ton per hour enclosed coal conveyors with particulate matter from enclosed drop points controlled by insertable dust filters and exhausting to Stacks S-2B and S-2C.

(E) Two (2) enclosed coal bunkers with a total loading capacity of 1800 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-3A and S-3B.

~~(2) Lime handling system~~

~~(A) Transfer of lime from truck or railcar by a closed pneumatic conveyor to lime storage silo.~~

~~(B) One (1) 300 ton per hour lime storage silo with particulate emissions controlled by a baghouse and exhausting to Stack S-1C.~~

(2) Lime and soda ash handling system, to be permitted in 2010:

(A) Transfer of lime from truck or railcar by a closed pneumatic conveyor to two (2) lime storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4A and S-4B.

(B) Transfer of soda ash from truck or railcar by a closed pneumatic conveyor to two (2) soda ash storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4C and S- 4D.

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

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

D.10.1 **Coal** ~~Material~~ Handling and Lime **and Soda Ash** Handling ~~Baghouse~~ **Particulate Matter** BACT Requirements [326 IAC 2-2-**3**]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for ~~grinding mill operations exhausting to Stack S-1A~~, coal receiving and unloading station emissions exhausting to Stack S-1B, **coal reclaim tunnel conveyor emissions exhausting to stack S-2A, coal conveyor emissions exhausting to Stacks S-1D, S-2B and S-2C, coal bunker emissions exhausting to Stacks S-3A and S-3B and** lime handling **emissions** ~~operations~~ exhausting to **Stacks S-4A and S-4B, and Soda Ash handling emissions exhausting to Stacks S-4C and S-4D** ~~Stack S-1C and coal drop point emissions exhausting to Stack S-1D~~ shall be as follows:

(a) Best management practices.

(b) PM emissions from the high efficiency baghouse, **insertable dust filters and bin vent dust collectors** shall not exceed a grain loading of 0.003 grains per dry standard cubic ~~feet~~ **foot** (gr/dscf).

(c) $PM/PM_{10}/PM_{2.5}$ emissions shall not exceed**;** ~~0.34 lbs/hr for each individual baghouse (coal receiving and unloading station, grinding mill operation, coal drop point and lime storage)~~

(A) 0.66 lbs/hr for the reclaim tunnel baghouse (Stack S-2A);

(B) 0.34 lbs/hr for the coal receiving and unloading station baghouse (Stack S-1B);

(C) 0.064 lb/hr for the bin vent dust collector associated with the coal bunker, identified as coal bunker #1 (Stack S-3A);

(D) 0.064 lb/hr for the bin vent dust collector associated with the coal bunker, identified as coal bunker #2 (Stack S-3B);

(E) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-002 Head Chute (Stack S-1D);

(F) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-003A Head Chute (Stack S-2B);

(G) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-003B Head Chute (Stack S-2C);

(H) **0.019 lb/hr for the bin vent dust collector associated with the lime silo, identified as Lime Silo #1(Stack S-4A);**

(I) **0.019 lb/hr for the bin vent dust collector associated with the lime silo, identified as Lime Silo #2 (Stack S-4B);**

(J) **0.019 lb/hr for the bin vent dust collector associated with the soda ash silo #1 (Stack S-4C); and**

(K) **0.019 lb/hr for the bin vent dust collector associated with the soda ash silo #2 (Stack S-4D).**

D.10.2 Particulate ~~Matter~~ Emissions **Limitation for manufacturing Processes** [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emissions from the coal receiving and handling and lime **and soda ash** handling shall not exceed the pounds per hour rate (E) when operating at a process weight of (P) tons per hour as determined by the following equation:

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

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

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

~~**Particulate Emission Limitations for Manufacturing Processes**~~		
~~**Emission Point**~~	~~**E** (lb/hr)~~	~~**P** (ton/hr)~~
~~Stack S-1A~~	~~61~~ 250	——
~~Stack S-1B~~	~~80~~ 1200	——
~~Stack S-1C~~	~~63~~ 300	——
~~Stack S-1D~~	~~61~~ 250	——

Particulate Emission Limitations for Manufacturing Processes			
Emission Point	**Unit Description**	**Process Weight Rate (TPH)**	**E (lb/hr)**
Stack S-2A	**Reclaim Tunnel**	**1800**	**85.4**
Stack S-1B	**Coal receiving and unloading station**	**1200**	**80**
Stack S1-D	**Conveyor MH-002 Head Chute**	**1200**	**80**
Stack S-2B	**Conveyor MH-003A Head Chute**	**900**	**76.2**
Stack S-2C	**Conveyor MH-003B Head Chute**	**900**	**76.2**
Stack S3-A	**Coal Bunker #1**	**1800**	**85.4**
Stack S-3B	**Coal Bunker #2**	**1800**	**85.4**
Stack S-4A	**Lime Silo #1**	**46**	**43.8**
Stack S-4B	**Lime Silo #2**	**46**	**43.8**
Stack S-4C	**Soda Ash Silo #1**	**46**	**43.8**

Particulate Emission Limitations for Manufacturing Processes			
Emission Point	**Unit Description**	**Process Weight Rate (TPH)**	**E (lb/hr)**
Stack S-4D	**Soda Ash Silo #2**	**46**	**43.8**

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

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for the baghouses.

Compliance Determination Requirements

D.10.4 Particulate Control [326 IAC 2-7-6(6)][326 IAC 6-3-2][326 IAC 2-2]

(a) Except as otherwise provided by statute or rule or in this permit, the baghouses, **dust collectors and dust filters** for PM control shall be in operation and control emissions at all times the associated coal ~~drop points~~, **reclaim tunnel,** receiving and unloading **station**, **coal conveyors, bunkers,** ~~grinding mill~~ and lime **and soda ash** facilities are in operation.

(b) Vendor guarantee that each baghouse**, dust collectors and dust filters** meets a grain outlet loading of 0.003 grains/dscf.

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

(a) Within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of the coal **reclaim** ~~pile drop point~~ operations, in order to demonstrate compliance with Condition D.10.1, the Permittee shall conduct initial performance test to measure the PM (which includes PM_{10} and $PM_{2.5}$ and filterable and condensable particulates), of exhaust air from Stack **S-2A** ~~S-1D~~, utilizing methods as approved by the Commissioner.

(b) Within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of **coal** receiving and unloading station, in order to demonstrate compliance with Condition D.10.1, the Permittee shall conduct initial performance test to measure the PM (which includes PM_{10} and $PM_{2.5}$ and filterable and condensable particulates), of exhaust air from Stack S-1B, utilizing methods as approved by the Commissioner.

(c) Within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of ~~grinding mill~~ **coal conveying** operations, in order to demonstrate compliance with Condition D.10.1, the Permittee shall conduct initial performance test to measure the PM (which includes PM_{10} and $PM_{2.5}$ and filterable and condensable particulates), of exhaust air from ~~Stack S-1A~~, **Stacks S-1D, S-2B and S-2C,** utilizing methods as approved by the Commissioner.

(d) Within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of the coal bunker operations, in order to demonstrate compliance with Condition D.10.1, the Permittee shall conduct initial performance test to measure the PM (which includes PM10 and PM2.5 and filterable and condensable particulates), of exhaust air from Stacks S-3A and S-3B, utilizing methods as approved by the Commissioner.

(~~d~~**e**) Within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of the lime **and soda ash** handling operations, in order to demonstrate compliance with Condition D.10.1, the Permittee shall conduct initial performance test to measure the PM (which includes PM_{10} and $PM_{2.5}$ and filterable and condensable particulates), of exhaust air from ~~Stack S-1C~~ **Stack S4-A, S-4B, S-4C and S-4D**, utilizing methods as approved by the Commissioner.

Testing shall be conducted in accordance with Section C – Performance Testing. These tests shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration.

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

D.10.6 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)] [40 CFR 64]

(a) Visible emission notations of each baghouse**, dust collector, and dust filter** exhausts shall be performed once per week during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

....

D.10.7 Baghouse Parametric Monitoring [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

(a) The Permittee shall record the pressure drop across each of the baghouses**, dust collectors and dust filters** used in conjunction with the coal **reclaim operations** ~~drop points~~, receiving and unloading station, ~~grinding mill~~ **coal conveyors, coal bunkers** and lime **and soda ash** facilities at least once per week when the facilities are in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range of 3.0 and 6.0 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. 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.

(b) The instrument used for determining the pressure shall comply with Section C - Instrument Specifications, and shall be calibrated in every 6 months. The specifications shall be available on site with the Preventive Maintenance Plan.

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

D.10.9 Record Keeping Requirements

(a) **In order to** ~~To~~ document compliance with Condition D.10.6 - Visible Emissions Notations, the Permittee shall maintain records of the visible emission notations of the transfer points, baghouse **dust collector and dust filter** exhausts **and** railcar unloading stations. ~~and all response steps taken and the outcome for each.~~ **The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).**

(b) **In order to** ~~To~~ document compliance with Condition D.10.7 - Baghouse Parametric Monitoring, the Permittee shall maintain records of the pressure drop across each baghouse **dust collector and dust filter**. **The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).**

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

Change 2: The new coal handling system has been added to Section G3 of the permit since the units are subject to 40 CFR 60, Subpart Y.

SECTION G.3 New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Coal receiving and handling system, to be permitted in 2010, except the truck or railcar receiving and unloading permitted in 2008, using enclosed conveyors consisting of the following equipment:

(A) 1200 ton per hour enclosed coal conveyor with particulate emissions from drop point to active coal pile stacking tube controlled by an insertable dust filter, exhausting to Stack S-1D.

(B) One (1) 1200 ton per hour truck or railcar receiving and unloading station with enclosed drop points and particulate emissions controlled by a baghouse and exhausting to Stack S-1B.

(C) One (1) 1,800 ton per hour reclaim tunnel, using two (2) 900 ton per hour conveyors with enclosed drop points and particulate matter controlled by a baghouse and exhausting to Stack S-2A.

(D) Two (2) 900 ton per hour enclosed coal conveyors with particulate matter from enclosed drop points controlled by insertable dust filters and exhausting to Stacks S-2B and S-2C.

(E) Two (2) enclosed coal bunkers with a total loading capacity of 1800 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-3A and S-3B.

~~Coal receiving and handling system, permitted in 2008, using enclosed conveyors consisting of the following equipment:~~

~~(A) 250 ton per hour coal pile drop point particulate emissions controlled by a baghouse, exhausting to Stack S-1D.~~

~~(B) One (1) 1200 ton per hour truck or railcar receiving and unloading station with enclosed drop points and particulate emissions controlled by a baghouse and exhausting to Stack S-1B.~~

~~(C) Two (2) enclosed 250 ton per hour coal grinding mills with particulate emissions controlled by a baghouse and exhausting to Stack S-1A.~~

Under the NSPS for Coal Preparation Plants (40 CFR 60, Subpart Y), these emission units are considered to be affected facilities in a coal preparation plant that will commence construction after October 24, 1974.

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

....

Change 3: The new Lime and soda ash handling system has been added to Section G4 of the permit since the units are subject to 40 CFR 60, Subpart OOO.

SECTION G.4 New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

Facility Description [326 IAC 2-7-5(15)] (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

(1) Lime and soda ash handling system, to be permitted in 2010:

(A) Transfer of lime from truck or railcar by a closed pneumatic conveyor to two (2) lime storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4A and S-4B.

(B) Transfer of soda ash from truck or railcar by a closed pneumatic conveyor to two (2) soda ash storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4C and S- 4D.

~~Lime handling system, permitted in 2008~~

~~(A) Transfer of lime from truck or railcar by a closed pneumatic conveyor to lime storage silo.~~

~~(B) One (1) 300 ton per hour lime storage silo with particulate emissions controlled by a baghouse and exhausting to Stack S-1C.~~

Under the NSPS for Nonmetallic Mineral Processing Plants (40 CFR 60, Subpart OOO), this emission unit is considered to be a fixed nonmetallic mineral processing plant containing conveyers, grinding mills and storage for which construction commenced after August 31, 1983.

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

....

Conclusion and Recommendation

The construction of this proposed modification shall be subject to the conditions of the attached proposed PSD/Significant Source Modification No. 083-28683-00003 and Significant Permit Modification No 083-28801-00003. The staff recommends to the Commissioner that this PSD/ Significant Source Modification and Part 70 Significant Permit Modification be approved.

Appendix A: Emissions Calculations
Emission Summary

Source Name: Duke Energy Indiana - Edwardsport Generating Station
Source Location: 15424 E St. Road 358, Edwardsport, IN 47258
Permit Number: PSD/SSM 083-28683-00003
Permit Reviewer: Josiah Balogun
Date: 1-Dec-2009

Uncontrolled Potential to Emit

		PM (tons/yr)	PM_{10} (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	HAPs (tons/yr)
System	**Emission Unit**							
Coal Material Handling	Reclaim Tunnel (S-2A)	2883.29	2883.29	0	0	0	0	0
	Conveyor MH-002 Head Chute (S -1D)	225.26	225.26	0	0	0	0	0
	Conveyor MH-003A Head Chute (S -2B)	225.26	225.26	0	0	0	0	0
	Conveyor MH-003B Head Chute (S -2C)	225.26	225.26	0	0	0	0	0
	Coal Bunker # (S-3A)	28.16	28.16	0	0	0	0	0
	Coal Bunker #2 (S-3B)	28.16	28.16	0	0	0	0	0
Makeup Water System Material Handling	Lime Silo #1 (S-4A)	8.17	8.17	0	0	0	0	0
	Lime Silo #2 (S-4B)	8.17	8.17	0	0	0	0	0
	Soda Ash Silo #1 (S-4C)	8.17	8.17	0	0	0	0	0
	Soda Ash Silo #2 (S-4D)	8.17	8.17	0	0	0	0	0
	Total Emissions	3648.1	3648.1	0	0	0	0.0	Single HAP <10 Combined HAPs < 25

Appendix A: Emissions Calculations
Emission Summary

Source Name: Duke Energy Indiana - Edwardsport Generating Station
Source Location: 15424 E St. Road 358, Edwardsport, IN 47258
Permit Number: PSD/SSM 083-28683-00003
Permit Reviewer: Josiah Balogun
Date: 1-Dec-2009

Limited Potential to Emit

		PM	PM_{10}	SO_2	VOC	CO	NOx	HAPs
System	**Emission Unit**							
Coal Material Handling	Reclaim Tunnel (S-2A)	2.88	2.88	0	0	0	0	0
	Conveyor MH-002 Head	0.23	0.23	0	0	0	0	0
	Conveyor MH-003A Head	0.23	0.23	0	0	0	0	0
	Conveyor MH-003B Head	0.23	0.23	0	0	0	0	0
	Coal Bunker # (S-3A)	0.28	0.28	0	0	0	0	0
	Coal Bunker #2 (S-3B)	0.28	0.28	0	0	0	0	0
Makeup Water System Material Handling	Lime Silo #1 (S-4A)	0.08	0.08	0	0	0	0	0
	Lime Silo #2 (S-4B)	0.08	0.08	0	0	0	0	0
	Soda Ash Silo #1 (S-4C)	0.08	0.08	0	0	0	0	0
	Soda Ash Silo #2 (S-4D)	0.08	0.08	0	0	0	0	0
Total for Modification		4.45	4.45	0.0	0.0	0.0	0.0	0.0
Total Emission		4.47	4.47	0	0	0	0	0
Total for Modification		-0.02	-0.02	0	0	0	0	Single HAP <10 Combined HAPs < 25

Source Name: Duke Energy Indiana - Edwardsport Generating Station
Source Location: 15424 E St. Road 358, Edwardsport, IN 47258
Permit Number: PSD/SSM 083-28683-00003
Permit Reviewer: Josiah Balogun
Date: 1-Dec-2009

System	Emission Point Description	Control Device	Grain Loading (gr/dscf)	Outlet Air Flow (cfm)	Emission Rate (lb/hr)	Emission Rate (TPY)	Control Device Efficiency (%)	Uncontrolled Emissions (TPY)
Coal Material Handling	S-2A Reclaim Tunnel	Baghouse	0.003	25,600	0.658	2.88	99.9	2883.29
	S-1D Conveyor MH-002 Head Chute	Insertable Dust Filter	0.003	2,000	0.051	0.23	99.9	225.26
	S-2B Conveyor MH-003A Head Chute		0.003	2,000	0.051	0.23	99.9	225.26
	S-2C Conveyor MH-003B Head Chute		0.003	2,000	0.051	0.23	99.9	225.26
	S-3A Coal Bunker #1	Bin Vent Dust Collector	0.003	2,500	0.064	0.28	99	28.16
	S-3B Coal Bunker #2		0.003	2,500	0.064	0.28	99	28.16
Makeup Water System Material Handling	S-4A Lime Silo #1	Bin Vent Dust Collector	0.003	725	0.019	0.08	99	8.17
	S-4B Lime Silo #2		0.003	725	0.019	0.08	99	8.17
	S-4C Soda Ash Silo #1		0.003	725	0.019	0.08	99	8.17
	S-4D Soda Ash Silo #2		0.003	725	0.019	0.08	99	8.17
Total PM/PM_{10}/$PM_{2.5}$ Emissions					**1.02**	**4.45**		**3648.04**

Methodology
lb/hr = grain loading x air flow x 60/7000
Control efficiency from Form CE-02 Particulate Control
Uncontrolled Emissions = controlled emission rate / (1-control efficiency)

Indiana Department of Environmental Management
Office of Air Quality

Appendix B – BACT Analyses
Technical Support Document (TSD)
Prevention of Significant Deterioration (PSD)

Source Background and Description

Source Name:	**Duke Energy Indiana - Edwardsport Generating Station**
Source Location:	**15424 East State Rd 358, Edwardsport, IN 47258**
County:	**Knox**
SIC Code:	**4911**
Operation Permit No.:	**T 083-7243-00003**
Operation Permit Issuance Date:	**August 10, 2004**
PSD/Significant Source Modification No.:	**PSD/SSM 083-28683-00003**
Significant Permit Modification No.:	**SPM 083-28801-00003**
Permit Reviewer:	**Josiah Balogun**

Proposed Modification

On January 25, 2008, the Office of Air Quality (OAQ) issued a permit (Permit No. PSD/SSM 083-23529-00003) to Duke Energy Indiana to construct an Integrated Gasification and Combined Cycle (IGCC) electric generating plant at the Edwardsport Generating Station site. A corresponding Significant Permit Modification (SPM No. T083-23531-00003) authorizing operation of the IGCC plant was issued by the OAQ on March 11, 2008.The IGCC plant would replace the existing electric generating units at the Edwardsport Generating Station. During construction planning for the material handling (coal and lime) facilities, Duke identified certain necessary design changes which require revision of certain previously permitted equipment and the installation of additional emitting equipment. Accordingly, this application constitutes a request for a PSD permit revision to address certain design revisions to the coal and lime material handling facilities of the proposed IGCC plant at the Edwardsport generating facility. Since this request presents additional emission units and modifications to its facilities and operations previously reviewed and permitted by IDEM under the PSD rules, these changes will be considered part of the original project and addressed in a revision to the previously issued PSD/SSM permit in 2008. No increase in allowable emissions of $PM/PM_{10}/PM_{2.5}$ will occur as a result of the additional emission units to be constructed at the plant.

Duke Energy Indiana - Edwardsport Generating Station, located at 15424 East State Rd 358, Edwardsport, IN, Indiana, in Knox County submitted a PSD/Significant Source Modification application to IDEM, OAQ on November 23, 2009.

Requirement for Best Available Control Technology (BACT)

326 IAC 2-2 requires a best available control technology (BACT) review to be performed on the proposed modification because the modification is a part of the original PSD/SSM 083-23529-00003, issued in January 25, 2008

Emission Units Subject to BACT Requirements for PM, PM10 and PM2.5

(1) Coal handling system, using enclosed conveyors consisting of the following equipment:

(A) 1200 ton per hour enclosed coal conveyor with particulate emissions from drop point to active coal pile stacking tube controlled by an insertable dust filter, exhausting to Stack S-1D.

(B) One (1) 1800 ton per hour reclaim tunnel, using two (2) 900 ton per hour conveyors with enclosed drop points and particulate matter controlled by a baghouse and exhausting to Stack S-2A.

(C) Two (2) 900 ton per hour enclosed coal conveyors with particulate matter from enclosed drop points controlled by insertable dust filters and exhausting to Stacks S-2B and S-2C.

(D) Two (2) enclosed coal bunkers with a total loading capacity of 1800 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-3A and S-3B.

(2) Lime and soda ash handling system, to be permitted in 2010:

(A) Transfer of lime from truck or railcar by a closed pneumatic conveyor to two (2) lime storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4A and S-4B.

(B) Transfer of soda ash from truck or railcar by a closed pneumatic conveyor to two (2) soda ash storage silos, each capable of handling a maximum loading rate of 46 tons per hour and with particulate matter controlled by bin vent dust collectors exhausting to Stacks S-4C and S-4D.

Summary of the Best Available Control Technology (BACT) Process

BACT is a mass emission limitation based on the maximum degree of pollution reduction of emissions, that is achievable, as determined on a case-by-case basis. BACT analysis takes into account the energy, environmental, and economic impacts on the source. These reductions may be determined through the application of available control techniques, process design, work practices, and operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause or contribute to air pollution, thereby protecting public health and the environment.

Federal guidance on BACT requires an evaluation that follows a "top down" process. In this approach, the applicant identifies the best-controlled similar source on the basis of controls required by regulation or permit, or controls achieved in practice. The highest level of control is then evaluated for technical feasibility.

The five (5) basic steps of a top-down BACT analysis are listed below:

Step 1: Identify Potential Control Technologies

The first step is to identify potentially “available” control options for each emission unit and for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emissions unit in question. The list should include lowest achievable emission rate (LAER) technologies and controls applied to similar source categories. There is no requirement in the State or Federal regulations to require innovative control to be used as BACT.

Step 2: Eliminate Technically Infeasible Options

The second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. It is important in this step that any presentation of a technical argument for eliminating a technology from further consideration be clearly documented based on physical, chemical, engineering, and source-specific factors related to safe and successful use of the controls. Innovative control means a control that has not been demonstrated in a commercial application on similar units. Innovative controls are normally given a waiver from the BACT requirements due to the uncertainty of actual control efficiency. IDEM evaluates any innovative controls proposed by the source. Duke Energy Indiana - Edwardsport Generating Station has not submitted any control technology. Only available and proven control technologies are evaluated. A control technology is considered available when there are sufficient data indicating that the technology results in a reduction in emissions of regulated pollutants.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern. The ranked alternatives are reviewed in terms of environmental, energy, and economic impacts specific to the proposed modification. If the analysis determines that the evaluated alternative is not appropriate as BACT due to any of the impacts, then the next most effective is evaluated. This process is repeated until a control alternative is chosen as BACT. If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical or economic evaluation, except for the environmental analyses.

Step 4: Evaluate the Most Effective Controls and Document the Results

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts.

Step 5: Select BACT

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern. For the technologies determined to be feasible, there may be several different limits that have been set as BACT for the same control technology. The permitting agency has to choose the most stringent limit as BACT unless the applicant demonstrates in a convincing manner why that limit is not feasible. The final BACT determination would be the technology with the most stringent corresponding limit that is economically feasible. BACT must, at a minimum, be no less stringent than the level of control required by any applicable New Source Performance Standard (NSPS) and National Emissions Standard for Hazardous Air Pollutants (NESHAP) or state regulatory standards applicable to the emission units included in the permits.

The Office of Air Quality (OAQ) makes BACT determinations by following the five steps identified above.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT – Coal Transferring and Handling

Step 1: Identify Potential Control Technologies

The emissions of particulate matter (PM) and the particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}) are generally controlled by the following add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere:

(1) Fabric Filter Dust Collectors (Baghouses);

(2) Wet Scrubber;

(3) Cyclones; and

(4) Wet Suppression.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

(a) **Wet Suppression:**
Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles. There are two types of wet suppression systems: liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems which supply foams as the wetting agent. Wet suppression systems typically achieve particulate control efficiencies of 50-70

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet suppression is a technically feasible option for the Coal handling system at this source.

(b) **Cyclones:**
Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution control equipment such as ESPs or baghouses. Cyclones are less efficient than wet scrubbers, baghouses, or ESPs. Cyclones used as pre-cleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment. This control technology may be more commonly used in industrial sites that generate a considerable amount of particulate matter, such as lumber companies, feed mills, cement plants, and smelters.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a cyclone is a technically feasible option for the Coal handling system at this source.

(c) **Wet Scrubber**

A wet scrubber is an air pollution control device that removes particulates from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove particulates. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the particulates size decreases. Collection efficiencies also vary with scrubber type. Collection efficiencies range from greater than 90% for venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are smaller and more compact than baghouses or ESPs. They have lower capital costs and comparable operation and maintenance (O&M) costs. Wet scrubbers are particularly useful in the removal of particulates with the following characteristics:

(1) Sticky and/or hygroscopic materials (materials that readily absorb water);

(2) Combustible, corrosive and explosive materials;

(3) Particles that are difficult to remove in their dry form;

(4) Particulates in the presence of soluble gases; and

(5) Particulates in waste gas streams with high moisture content.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet scrubber is a technically feasible option for the Coal handling system at this source.

(d) **Fabric Filtration:**

A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9%. The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake. Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 1 to 20 inches of water. Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation and that cannot be economically accommodated. Important process variables include particle characteristics, gas characteristics, and fabric properties. The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a fabric filter is a technically feasible option for the Coal handling system at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The above control technologies have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from operation of a coal handling system.

(1) Fabric Filtration (99% - 99.9% PM/PM10/PM2.5 Reduction);

(2) Wet Scrubber (90% PM/PM10/PM2.5 Reduction);

(3) Cyclones (80% PM/PM10/PM2.5 Reduction); and

(4) Wet Suppression (50-70% PM/PM10/PM2.5 Reduction).

As shown above, baghouse control of coal handling operations achieves a control efficiency of greater than 99% versus the wet scrubber, cyclone and wet suppression control efficiency of 90%, 80% and 50-70%, respectively. Thus, the use of a baghouse is the top ranked control alternative for control of particulate matter emissions from the coal handling system.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed $PM/PM_{10}/PM_{2.5}$ BACT determination along with the existing $PM/PM_{10}/PM_{2.5}$ BACT determinations for coal receiving and handling. All data in the table is based on the information obtained from the permit application submitted by Duke Energy Indiana - Edwardsport Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

Comparison with other BACT Limitations:

Table 1 presents BACT limits for $PM/PM_{10}/PM_{2.5}$ emissions from coal handling operations. The limit being proposed by Duke is equivalent to or lower than the BACT limitations established for coal handling operations at these facilities.

Table 1: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits - Coal Transferring and Handling

Facility	State	Date	PM/PM_{10} BACT Limit	BACT Control Method
Energy Indiana – Edwardsport Generating Station (Proposed permit 083-28683-00003)	IN	Proposed	Coal Reclaim Tunnel - 0.003 gr/dscf and 0.66 lbs/hr Conveyors, MH-002, 003A and 003B - 0.003 gr/dscf and limit of 0.051 lbs/hr, each Coal Bunker #1 and #2 - 0.003gr/dscf and limit of 0.064 lbs/hr, each	Best management Practices and use of high efficiency baghouse or filter.
Ohio River Clean Fuels, LLC	OH	11/20/08	0.1200 lb/hr, 0.600 tpy	Baghouse and dust collector, totally enclosed coal and biomass unloading and conveyors from building, including all transfer points

Table 1: Existing PM/PM_{10}/$PM_{2.5}$ BACT Limits - Coal Transferring and Handling

Facility	State	Date	PM/PM_{10} BACT Limit	BACT Control Method
American Municipal Power	OH	02/07/08	9 tpy per rolling 12-month period	Use of baghouse with option of enclosure, fogging, wet suppression
Homeland Energy Solutions, LLC	IA	08/28/07	0.005 gr/dscf	Use of baghouse water fogging. (Baghouse used to control storage bins and water fogging used to eliminate PM in unloading area
Taylorville Energy Center – Illinois	IL	06/15/07	0.01 gr/dscf 0.84 tons/year (handling and storage).	Use of enclosure and use of fabric filter or baghouse if necessary.
Western Farmers Electric Coop	OK	02/09/07	0.01 gr/dscf	Fabric filter baghouse
Cutler-Magner Company	WI	08/16/06	0.04 lbs/hr, 0.005 gr/dscf	Fabric filter baghouse and total enclosure of operation
Western Greenbrier Co-Generation, LLC	WV	04/26/06	0.01 gr/dscf	Fabric filter
Lamar Utilities Board DBA Lamar Light and Power	CO	02/03/06	0.02 lb/ton	High efficiency fabric filter baghouse (99.5%)
Public Service Company of Colorado	CO	070/5/05	0.01 gr/dscf	Use of water sprays, lowering wells, dust suppressants, enclosures and baghouses
Montana Dakota Utilities/Westmoreland Power	ND	06/03/05	PM – 0.005 gr/dscf	99.9% reduction and use of baghouse

Table 1: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits - Coal Transferring and Handling				
Facility	**State**	**Date**	**PM/PM_{10} BACT Limit**	**BACT Control Method**
Red Tail Energy, LLC	ND	08/04/04	PM/PM_{10} – 0.004 gr/dscf	99.8% reduction and use of baghouse

(a) **Proposed BACT Limit**:

The following has been proposed as BACT by Duke Energy Indiana - Edwardsport Generation Station for particulate matter from coal handling:

(1) Best management practices.

(2) PM control system with documented PM outlet concentration of 0.003 grains per dry standard cubic foot and PM/PM10/PM2.5 emission shall not exceed the following:

(A) 0.66 lbs/hr for the reclaim tunnel baghouse (Stack S-2A);

(B) 0.064 lb/hr for the bin vent dust collector associated the coal bunker, identified as coal bunker #1 (Stacks S-3A); and

(C) 0.064 lb/hr for the bin vent dust collector associated the coal bunker, identified as coal bunker #2 (Stacks S-3B); and

(D) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-002 Head Chute (Stacks S-1D).

(E) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-003A Head Chute (Stacks S-2B).

(F) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-003B Head Chute (Stacks S-2C).

(b) **Comparison with other BACT Limitations:**

Table 1 presents BACT limits for $PM/PM_{10}/PM_{2.5}$ emissions from the coal receiving and handling operations. The limit being proposed by Duke is equivalent to or lower than the BACT limitations established for coal handling operations at these facilities.

(c) **New Source Performance Standards**

The limit proposed by Duke Energy Indiana - Edwardsport Generating Station is more stringent than the NSPS limit. The NSPS limit is 0.01 grains per dry standard cubic foot but the limit proposed by Duke Energy Indiana is 0.003 grains per dry standard cubic foot.

Step 5: Select BACT

The IDEM agrees that the PM/PM10/PM2.5 BACT for coal handling and transferring shall be as follows:

(1) Best management practices.

(2) A baghouse with documented PM outlet concentration of 0.003 grains per dry standard cubic foot and PM/PM10/PM2.5 emission shall not exceed:

(A) 0.66 lbs/hr for the reclaim tunnel baghouse (Stack S-2A).

(3) A bin vent dust collector with documented PM outlet concentration of 0.003 grains per dry standard cubic foot and PM/PM10/PM2.5 emission shall not exceed the following:

(A) 0.064 lb/hr for the bin vent dust collector associated the coal bunker, identified as coal bunker #1 (Stack S-3A); and

(B) 0.064 lb/hr for the bin vent dust collector associated the coal bunker, identified as coal bunker #2 (Stack S-3B).

(4) An insertable dust collector with documented PM outlet concentration of 0.003 grains per dry standard cubic foot and PM/PM10/PM2.5 emission shall not exceed the followings;

(A) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-002 Head Chute (Stack S-1D);

(B) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-003A Head Chute (Stack S-2B); and

(C) 0.051 lb/hr for the insertable dust filter on the conveyor drop point, identified as Conveyor MH-003B Head Chute (Stack S-2C).

Particulate Matter (PM/PM_{10}/$PM_{2.5}$) BACT – Lime and Soda Ash Receiving, Transferring and Handling

Step 1: Identify Potential Control Technologies

The emissions of particulate matter (PM) and the particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}) are generally controlled by the following add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere:

(1) Fabric Filter Dust Collectors (Baghouses);

(2) Wet Scrubber;

(3) Cyclones; and

(4) Wet Suppression.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

(a) **Wet Suppression:**
Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles. There are two types of wet suppression systems: liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems which supply foams as the wetting agent. Wet suppression systems typically achieve PM control efficiencies of 50-70

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet suppression is a technically feasible option for the Lime and Soda Ash receiving and handling system at this source.

(b) **Cyclones:**
Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution control equipment such as ESPs or baghouses. Cyclones are less efficient than wet scrubbers, baghouses, or ESPs. Cyclones used as pre-cleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment. This control technology may be more commonly used in industrial sites that generate a considerable amount of particulate matter, such as lumber companies, feed mills, cement plants, and smelters.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a cyclone is a technically feasible option for the Lime and Soda Ash receiving and handling system at this source.

(c) **Wet Scrubber**

A wet scrubber is an air pollution control device that removes particulates from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove particulates. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the particulates size decreases. Collection efficiencies also vary with scrubber type. Collection efficiencies range from greater than 90% for venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are smaller and more compact than baghouses or ESPs. They have lower capital costs and comparable operation and maintenance (O&M) costs. Wet scrubbers are particularly useful in the removal of particulates with the following characteristics:

(1) Sticky and/or hygroscopic materials (materials that readily absorb water);

(2) Combustible, corrosive and explosive materials;

(3) Particles that are difficult to remove in their dry form;

(4) Particulates in the presence of soluble gases; and

(5) Particulates in waste gas streams with high moisture content.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet scrubber is a technically feasible option for the Lime and Soda Ash receiving and handling system at this source.

(d) **Fabric Filtration:**
A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9%. The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake. Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 1 to 20 inches of water. Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation and that cannot be economically accommodated. Important process variables include particle characteristics, gas characteristics, and fabric properties. The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a fabric filter is a technically feasible option for the Lime and Soda Ash receiving and handling system at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The above control technologies have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from operation of a Lime and Soda Ash receiving and handling system.

(1) Fabric Filtration (99% - 99.9% PM/PM10/PM2.5 Reduction);

(2) Wet Scrubber (90% PM/PM10/PM2.5 Reduction);

(3) Cyclones (80% PM/PM10/PM2.5 Reduction); and

(4) Wet Suppression (50-70% PM/PM10/PM2.5 Reduction).

As shown above, baghouse control of the makeup water system material (lime and soda ash) handling achieves a control efficiency of greater than 99% versus the wet scrubber, cyclone and wet suppression control efficiency of 90%, 80% and 50-70%, respectively. Thus, the use of a baghouse is the top ranked control alternative for control of particulate matter emissions from the makeup water system material (lime and soda ash) handling system.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed $PM/PM_{10}/PM_{2.5}$ BACT determination along with the existing $PM/PM_{10}/PM_{2.5}$ BACT determinations for Lime and Soda Ash receiving and handling. All data in the table is based on the information obtained from the permit application submitted by Duke Energy Indiana - Edwardsport Generating Station, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

Table 2: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits - Lime and Soda Ash Handling

Facility	State	Date	BACT Limit*	BACT Control Method
Energy Indiana – Edwardsport Generating Station (Proposed permit 083-28683-00003)	IN	Proposed	two (2) Lime silo and two (2) Soda Ash Handling - 0.003 gr/dscf and limit of 0.019 lbs/hr, each.	Best management Practices and use of bin vent dust collector.
Martin Marietta	OH	11/13/08	0.0050 gr/dscf 3.32 tpy	Baghouse with 99.5% capture efficiency
Tate & Lyle Ingredients Americas, Inc.	IA	09/19/08	0.0050 gr/dscf Average of three stack test runs	Dust Collector
Louisiana Generating, LLC – Big Cajun I Power Plant	LA	01/08/08	0.22 lb/hr 0.01 tpy	Fabric Filters
Entergy Louisiana LLC	LA	11/30/07	No emission limit	Fabric Filter
University of Northern Iowa	IA	05/03/07	PM/PM_{10} – 0.005 gr/dscf	Use of a baghouse
Cutler-Magner Company	WI	08/19/06	PM –0.56 lbs/hr, 0.0114 gr/dscm	Use of a fabric filter baghouse and total enclosure of operation

Table 2: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits - Lime and Soda Ash Handling

Facility	State	Date	BACT Limit*	BACT Control Method
Western Greenbrier Co-Generation, LLC	WV	04/26/06	PM– 0.01 gr/dscf	use of fabric filters
Lamar Utilities Board DBA Lamar Light and Power	CO	02/03/06	0.045 lb/ton	Use of high efficiency fabric filter baghouse (99.5%)
United Wisconsin Grain Producers	WI	08/14/03	$PM/PM_{10}/PM_{2.5}$ – 2.00 lbs/hr	Use of a baghouse and enclosed pit
Public Service Company of Colorado	CO	07/05/05	PM/PM_{10} 0.015 gr/dscf	Use of a baghouse
Montana Dakota Utilities/Westmoreland Power	ND	06/03/05	PM – 0.005 gr/dscf	99.9% reduction and use of baghouse
Chemical Company - *Based on several processes	AL	03/23/05	PM – 0.005 gr/dscf, 0.009 gr/dscf or 0.0114 gr/dscf (calculated)	

(a) **Proposed BACT Limit**:

The following has been proposed as BACT for particulate matter from makeup water system material (lime and soda ash) handling:

(1) Best management practices.

(2) PM control system with documented PM outlet concentration of 0.003 grains per dry standard cubic foot and PM/PM10/PM2.5 shall not exceed;

(A) 0.019 lb/hr for the bin vent dust collector associated with the lime silo, identified as Lime Silo #1(Stack S-4A);

(B) 0.019 lb/hr for the bin vent dust collector associated with the lime silo, identified as Lime Silo #2 (Stack S-4B);

(C) 0.019 lb/hr for the bin vent dust collector associated with the soda ash silo #1 (Stack S-4C); and

(D) 0.019 lb/hr for the bin vent dust collector associated with the soda ash silo #2 (Stack S-4D).

(b) **Comparison with other BACT Limitations:**

Table 2 presents BACT limits for $PM/PM_{10}/PM_{2.5}$ emissions from the makeup water system material (lime and soda ash) handling operations. The limit being proposed by Duke is equivalent to or lower than the BACT limitations established for lime handling operations at these facilities.

(c) **New Source Performance Standards**

There are no established NSPS requirements that apply to PM emissions from the proposed makeup water system material (lime and soda ash) handling operations.

Step 5: Select BACT

The IDEM agrees that the PM/PM10/PM2.5 BACT for Lime Handling Operations shall be as follows :

(1) Best management practices.

(2) A bin vent dust collector system with documented PM outlet concentration of 0.003 grains per dry standard cubic foot and PM/PM10/PM2.5 shall not exceed the followings;

(A) 0.019 lb/hr for the bin vent dust collector associated with the lime silo, identified as Lime Silo #1(Stack S-4A).

(B) 0.019 lb/hr for the bin vent dust collector associated with the lime silo, identified as Lime Silo #2 (Stack S-4B).

(C) 0.019 lb/hr for the bin vent dust collector associated with the soda ash silos #1 (Stack S-4C).

(D) 0.019 lb/hr for the bin vent dust collector associated with the soda ash silos #2 (Stack S-4D).

Air Quality Analysis

Duke Energy Indiana (Duke)

Edwardsport Station

Edwardsport, Indiana (Knox County)

Tracking and Plant ID: 083-28683-00003

Proposed Project

Duke Energy Indiana (Duke), Edwardsport Generating Station, has submitted a request for a significant source modification of their facility to shutdown four boilers and a coal transfer system and construct and operate a new Integrated Gasification Combined Cycle (IGCC) electricity generating system.

Malcolm Pirnie, prepared the permit application for Duke. The Modeling Section in the Office of Air Quality (QAQ) received the permit application August 18, 2006. The modeling information was received August 2007. Updated modeling information was received December 1, 2009. Changes include new material handling sources and changes to some structure and stack locations and heights. This technical support document provides the air quality analysis review of the permit application.

Analysis Summary

This reevaluation of the air quality impact of the IGCC plant project, as revised by the pending source modification request, showed no significant change in the results of the original air quality impact evaluation. The significant impact analysis for CO and PM_{10} determined that modeling concentrations exceeded the significant impact levels. Voluntary analysis was conducted for SO_2 and NO_2. A refined analysis was required and showed no violation of the NAAQS and the PSD increment. (Pre-construction monitoring requirements are not necessary since nearby monitoring was available from Daviess, Dubois, and Vanderburgh Counties.) The current Project was found to have no effect on the previous additional impact analysis and HAP analysis, both of which indicated acceptable results in the original permit proceeding.

Air Quality Impact Objectives

The purpose of the air quality impact analysis in the permit application is to accomplish the following objectives. Each objective is individually addressed in this document in each section outlined below.

A. Establish which pollutants require an air quality analysis based on PSD significant emission rates.

B. Provide analyses of actual stack heights with respect to Good Engineering Practice (GEP), the meteorological data used, a description of the model used in the analysis, and the receptor grid utilized for the analyses.

C. Determine the significant impact level, the area impacted by the source's emissions, and background air quality levels.

D. Demonstrate that the source will not cause or contribute to a violation of the National Ambient Air Quality Standard (NAAQS) or PSD increment if the applicant exceeds significant impact levels.

E. Perform a qualitative analysis of the source's impact on general growth, soils, vegetation and visibility in the impact area with emphasis on any Class I areas. The nearest Class I area is Kentucky's Mammoth Cave National Park.

F. Perform a Hazardous Air Pollutant (HAP) screening for informational purposes.

G. Summarize the Air Quality Analysis.

Section A - Pollutants Analyzed for Air Quality Impact

Applicability

The PSD requirements, 326 IAC 2-2, apply in attainment and unclassifiable areas and require an air quality impact analysis of each regulated pollutant emitted at the above significant levels by a major stationary source or modification. Significant emission levels for each pollutant are defined in 326 IAC 2-2-1 and in the Code of Federal Regulations (CFR) 52.21(b) (23) (i).

Proposed Project Emissions

VOCs, PM_{10}, NO_2, SO_2, CO, Pb, Fluorides, and Sulfuric Acid Mist are the pollutants that will be emitted from Duke Energy. The net emissions increase/decrease for this project is summarized below in Table 1. PM_{10} and CO potential net emissions after controls exceed the PSD significant emission rates and require an air quality analysis. Since the emissions for the project for all pollutants are above the significant emission rate, they are included in the air quality analysis.

TABLE 1
Significant Emission Rates for PSD

POLLUTANT	NEW SOURCE EMISSION RATE (facility total[3] – tpy)	DECOMISSIONED SOURCE EMISSION RATE (facility total – tpy)	NET PROJECT EMISSION RATE (facility total – tpy)	SIGNIFICANT EMISSION RATE (tpy)	PRELIMINARY AIR QUALITY ANALYSIS REQUIRED?
VOC[1] 87.6		6.9	80.67	40	No[1]
PM_{10}	446.82	207.31	239.5	15	Yes
NO_2 2416.49		2384.0	32.49	40	No
SO_2 465.3		10299.0	-9833.7	40	No
CO	1284.04	69.14	1214.9	100	Yes
Pb 0.037		0.0575	-0.0204	0.6	No
Fluorides[2] 0.0		20.67	-20.67	3	No
Sulfuric Acid Mist[2]	56.1 515.0		-458.9	7	No

[1] An air quality analysis is not performed for VOCs because they are photochemically reactive Photochemical models like UAM-V are used in regulatory or policy assessments to simulate the impacts from all sources by estimating pollutant concentrations and deposition of both inert and chemically reactive pollutants over large spatial scales. Currently, U.S. EPA has no regulatory photochemical models which can take into account small spatial scales or single source PSD modeling for ozone.
[2] Fluorides have monitoring concentration thresholds listed in 326 IAC 2-2-4. There is no National Ambient Air Quality Standard for this pollutant. Sulfuric Acid Mist has no monitoring threshold or National Ambient Air Quality Standard. No AQ analysis is required for Sulfuric Acid Mist under the PSD regulations.

[3]Worst case VOC emissions were based on startup/shutdown/trip operation. All other pollutant emission rates are based on normal operation for 8760 hours/year.

These are IDEM's permitted emission rates that are taken from their emissions calculation sheets on page 27 of Appendix A. These are also the emission rates that were modeled. Worst-case emission rates for both normal and startup/shutdown/trip operation scenarios were modeled for comparison with short-term impact standards while impacts from normal operation emissions were compared with annual standards.

Section B – Good Engineering Practice (GEP), Met Data, Model Used, Receptor Grid and Terrain

Stack Height Compliance with Good Engineering Practice (GEP)

This evaluation was originally performed in support on the initial permitting effort for the IGCC plant. The changes being proposed as part of the significant source modification request could affect the results of the initial analysis since new and modified stacks are proposed as part of the pending project. Consequently, the previous evaluation of the IGCC plant's compliance with GEP requirements was revised to include an assessment of any modified or new stacks of PM-emitting structures associated with the proposed project.

Applicability

Stacks should comply with GEP requirements established in 326 IAC 1-7-4. If stacks are lower than GEP, excessive ambient concentrations due to aerodynamic downwash may occur. Dispersion modeling credit for stacks taller than 65 meters (213 feet) are limited to GEP for the purpose of establishing emission limitations. The GEP stack height takes into account the distance and dimensions of nearby structures, which affects the downwind wake of the stack. The downwind wake is considered to extend five times the lesser of the structure's height or width. A GEP stack height is determined for each nearby structure by the following formula:

$$Hg = H + 1.5L$$

Where:
- Hg is the GEP stack height
- H is the structure height
- L is the structure's lesser dimension (height or width)

New Stacks

Since the new stack heights for Duke Energy' project are below GEP stack height, the effect of aerodynamic downwash will be accounted for in the air quality analysis for the project.

Meteorological Data

The meteorological data used in AERMOD consisted of 1986 through 1990 surface data from the Evansville, Indiana and upper air measurements taken at Peoria, Illinois. The meteorological data was downloaded from Lakes Environmental and preprocessed using AERMET.

Model Description

Malcolm Pirnie used the Breeze version of AERMOD, which is the same air quality model used for the previous permitting effort. OAQ used the most up to date BEEST (Version 09292) to determine maximum off-property concentrations or impacts for each pollutant. All regulatory default options were utilized in the U.S. EPA approved model, as listed in the 40 Code of Federal Register Part 51, Appendix W "Guideline on Air Quality Models".

Receptor Grid

OAQ modeling used the same receptor grids generated by Malcolm Pirnie, which are unchanged from the receptor grids used in the air quality modeling for the initial permitting effort for the IGCC plant. The receptor grid contains 5782 individual receptors.

- 100 meter spacing along the facility's property boundary,
- 100 meter spacing from 0 to 2,000 meters from the facility,
- 250 meters spacing from 2,000 to 5,000 meters from the facility,
- 1,000 meters spacing from 5,000 to 10,000 meters from the facility.

Treatment of Terrain

Receptor terrain elevation inputs were interpolated from DEM (Digital Elevation Model) data obtained from the USGS. DEM terrain data was preprocessed using AERMAP. The terrain files that were used in the terrain analysis can be found on the CD-ROM in Appendix A of the air quality technical support document provided by Malcolm Pirnie. These model inputs were unchanged from the initial permitting effort for the IGCC plant.

Section C - Significant Impact Level/Area (SIA) and Background Air Quality Levels

A significant impact analysis was conducted to determine if the source would exceed the PSD significant impact levels (concentrations). If the source's concentrations exceed these levels, further air quality analysis is required. Refined modeling for CO, PM_{10}, SO_2, and NO_2 was required because the results did exceed significant impact levels. Significant impact levels are defined by the following time periods in Table 2 below with all maximum-modeled concentrations from the worst case operating scenarios.

TABLE 2
Significant Impact Analysis

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS (ug/m^3)	SIGNIFICANT IMPACT LEVEL (ug/m^3)	REFINED AQ ANALYSIS REQUIRED
NO_2	Annual*	10.5	1	Yes
PM_{10}	Annual*	3.83	1	Yes
PM_{10}	24 hour*	28.3	5	Yes
SO_2	3 hour*	694	25	Yes
SO_2	24 hour*	196	5	Yes
SO_2	Annual*	22.1	1	Yes

CO	1 hour*	5507	2000	Yes
CO	8 hour*	2198	500	Yes

*First highest values per EPA NSR manual October 1990. Impacts are from the Duke Energy' project only.

Pre-construction Monitoring Screening Analysis

This evaluation was performed in support on the initial permitting effort for the IGCC plant. The changes being proposed as part of the significant source modification request will not affect the results of the original analysis. Consequently, the information provided below is for informational purposes only to maintain an understanding that this evaluation was previously performed and is not affected by the proposed change.

Applicability

The PSD rule, 326 IAC 2-2-4, requires an air quality analysis of the new source or the major modification to determine if the pre-construction monitoring threshold is triggered. In most cases, monitoring data taken from a similar geographic location can satisfy this requirement if the pre-construction monitoring threshold has been exceeded. Also, post construction monitoring could be required if the air quality in that area could be adversely impacted by applicant's emissions.

Modeling Results

The modeling results were compared to the PSD preconstruction monitoring thresholds. The results are shown in the table below.

TABLE 3
Preconstruction Monitoring Analysis

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS (ug/m^3)	DEMINIMIS LEVEL (ug/m3)	ABOVE DE MINIMIS LEVEL
NO_2 Annual*		10.5	14	No
PM_{10}	24 hour*	28.3	10	Yes
SO_2	24 hour*	196	13	Yes
CO	8 hour*	2198	575	Yes

*First highest values per EPA NSR manual October 1990. Maximum modeled impacts are from Duke Energy only.

CO, PM_{10} and SO_2 did trigger the preconstruction monitoring threshold level. Duke Energy can satisfy the preconstruction monitoring requirement since there is air quality monitoring data representative of the area in Daviess, Dubois, Gibson and Vanderburgh Counties.

Background Concentrations

Applicability

EPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (EPA-450/4-87-007) Section 2.4.1 is cited for approval of the monitoring sites for this area.

Background Monitors

Background data was taken from the monitoring stations closet to Duke Energy' Edwardsport Station. The closest SO_2 station is located in Daviess County. The closest PM_{10} monitoring station is located in Dubois County. The closest CO and NO_2 monitors are located in Vanderburgh County.

For all 24-hour background concentrations, the averaged second highest monitoring values were used. Annual background concentrations were taken from the maximum annual values.

TABLE 4
Existing Monitoring Data Used For Background Concentrations *

Pollutant	Monitoring Site	Averaging Period	Concentration (ug/m3)
NO_2	18-163-0012	Annual	19.4
PM_{10}	18-037-2001	Annual	26
PM_{10}	18-037-2001	24 hour	46.3
CO	18-163-0019	1 hour	3698
CO	18-163-0019	8 hour	2259
SO_2	18-027-0002	3 hour	225.3
SO_2	18-027-0002	24 hour	76
SO_2	18-027-0002	Annual	19.4

*OAQ used the most conservative values for the air quality analysis. It is standard policy to use the latest 3 years of data.

Section D - NAAQS and PSD Increment

NAAQS Compliance Analysis and Results

OAQ supplied emission inventories of all point sources within a 50-kilometer radius of Duke Energy's Edwardsport project site. The NAAQS inventories are generated from the Emission Inventory Tracking System (EMITS) in accordance with 326 IAC 2-6. The PSD increment inventories include sources that affect the increment and are compiled from permits issued by IDEM. Existing source data was included in the air quality impact evaluation (i.e., PSD Class II and NAAQS compliance demonstrations) for emissions of PM_{10}. The existing source data employed in support of the initial application was also used for this updated (as designed) analysis.
.

NAAQs modeling for the appropriate time-averaging periods for NO_2, PM_{10} and SO_2 was conducted and compared to the respective NAAQs limit. OAQ modeling results are shown in Table 5. All maximum-modeled concentrations were compared to the respective NAAQS limit. All maximum-modeled concentrations during the five years were below the NAAQS limits and further modeling was not required.

TABLE 5[6]
NAAQS Analysis

Pollutant	Year	Time-Averaging Period	Maximum Concentration ug/m3	Background Concentration ug/m3	Total ug/m3	NAAQS Limit ug/m3	NAAQS Violation
NO_2	1987	Annual[4]	10.5	19.4	29.9	100	NO
PM_{10}	1987	Annual[4]	3.8	26	29.8	50	NO
PM_{10}	1990	24 hour	23.9	46.3	70.2	150	NO
CO	1989	1 hour	5314	3698	9012	40000	NO
CO	1987	8 hour	1910	2259	4169	10000	NO
SO_2	1989	3 Hour[5]	591	225	816	1300	NO
SO_2	1989	24 hour[5]	168	76	244	365	NO
SO_2	1991	Annual[4]	22.1	19.4	41.5	80	NO

[4] First highest values per EPA NSR manual October 1990.
[5] High 2nd high values per EPA NSR manual October 1990.
[6] Any differences between the maximum concentration numbers in Tables 5 and 6 are due to different sources used for the NAAQS and the increment inventories. Table 2 maximum concentrations are from Duke Energy only.

Analysis and Results of Source Impact on the PSD Increment

Applicability

Maximum allowable increases (PSD increments) are established by 326 IAC 2-2-6 for NO_2, SO_2, and PM_{10}. This rule also limits a source to no more than 80 percent of the available PSD increment to allow for future growth.

Source Impact

Since the impact for NO_2, SO_2, and PM_{10} modeled above significant impact levels, as discussed above, a PSD increment analysis for Duke Energy's project and surrounding sources was required. Results of the increment modeling are summarized in Table 6 below.

TABLE 6[9]
Increment Analysis

Pollutant	Year	Time-Averaging Period	Maximum Concentration ug/m3	PSD Increment ug/m3	Percent Impact on the PSD Increment	Increment Violation
NO_2	1987	Annual[7]	10.5	25	42.0	NO
PM_{10}	1987	Annual[7]	3.8	17	22.3	NO
PM_{10}	1990	24 hour[8]	23.9	30	79.7	NO
SO_2	1989	Annual[7]	2.9	20	14.5	NO
SO_2	1989	3 hour[8]	84.1	512	16.4	NO
SO_2	1989	24 hour[8]	24.6	91	27.0	NO

[7] First highest value per EPA NSR manual October 1990.
[8] Highest second high per EPA NSR manual October 1990.
[9] Any differences between the maximum concentration numbers in Tables 5 and 6 are due to different sources used for the NAAQS

and the increment inventories. Table 2 maximum concentrations are from Duke Energy only.

The results of the increment analysis show all pollutants for all averaging periods were below 80% of the available increment. No further analysis is required.

Part E – Qualitative Analysis

Additional Impact Analysis

All PSD permit applicants must prepare additional impacts analysis for each pollutant subject to regulation under the Act. This analysis assesses the impacts on growth, soils and vegetation, endangered species and visibility caused by any increase in emissions of any regulated pollutant from the source. The Duke Energy modeling submittal provided an additional impact analysis performed by Malcolm Pirnie.

Economic Growth

The purpose of the growth analysis is to quantify project associated growth and estimate the air quality impacts from this growth either quantitatively or qualitatively.

The addition of the IGCC plant at the Edwardsport facility should not result in any noticeable residential growth in the area. Commercial growth is anticipated to occur at a gradual rate in the future. However, this growth will not be directly associated with the proposed IGCC project. Since the area is predominately rural, it is not expected the growth impacts will cause a violation of the NAAQs or the PSD increment.

Soils and Vegetation Analysis

A list of soil types present in the general area was determined. Soil types include the following: Sandy and Loamy Lacustrine deposits and Eolian sand, Alluvial and Outwash deposits, Eolian sand deposits.

Due to the agricultural nature of the land, crops in the Knox County area consist mainly of corn, sorghum, wheat, soybeans, and oats (2002 Agricultural Census for Knox County). The maximum modeled concentrations for Duke Energy' project are well below the threshold limits necessary to have adverse impacts on the surrounding vegetation such as autumn bent, nimblewill, barnyard grass, bishopscap and horsetail, and milkweed (Flora of Indiana – Charles Deam). Livestock in Knox County consist mainly of hogs, cattle, and sheep (2002 Agricultural Census for Knox County) and will not be adversely impacted from the facility. Trees in the area are mainly hardwoods. These are hardy trees and no significant adverse impacts are expected due to modeled concentrations.

Federal and State Endangered Species Analysis

Federal and state endangered or threatened species are listed by the U.S. Fish and Wildlife Service; Division of Endangered Species for Indiana and includes 5 amphibians, 27 birds, 10 fishes, 7 mammals, 15 mollusks, and 15 reptiles. Of the federal and state endangered species on the list, 2 amphibians, 7 reptiles, 16 mollusks, 7 fish, 18 birds, and 4 mammals have habitat within Knox County. The mollusks, fish, amphibians and certain species of birds and mammals are found along rivers and lakes while the other species of birds and mammals are found in forested areas. The facility is not expected to have any additional adverse effects on the habitats of the species than what has already occurred from the industrial, farming, and residential activities in the area.

Federal and state endangered or threatened plants are listed by the U.S. Fish and Wildlife

Service, Division of Endangered Species for Indiana. They list 22 state significant species of plants. At this time no federally endangered plant species are found in Knox County. The endangered plants do not thrive in industrialized and residential areas. The facility is not expected to adversely affect any plant on the endangered species list.

Visibility Analysis

The VISCREEN model is designed as a screening model to determine the visual impact parameters from a single source plume. It is used basically to determine whether or not a plume is visible as an object itself. The visibility impairment analysis considers the impacts that occur within the impact area of the source as defined by the user distances. The user distances are determined by the nearest interstate or airport. EPA has defined these locations in guidance to the state.

The PM_{10} and NOx emissions limits were used to run a local visibility Level 1 and a Level 2 analysis. VISCREEN Version 1.01 was used to determine if the color difference parameter (Delta-E) or the plume (green) contrast limits were exceeded. The Delta-E was developed to specify the perceived magnitude of color and brightness changes and is used as the primary basis for determining the perceptibility of plume visual impacts. The plume constant can be defined at any wavelength as the relative difference in the intensity (called spectral radiance) between the viewed object and its background. This is used to determine how the human eye responds differently to different wavelengths of light. The Delta-E of 2.0 and the plume contrast of 0.05 were not exceeded at the nearest interstate location along the proposed I-69.

Potential visibility impacts to Mammoth Cave National Park (further than 200 km from Duke Energy) would be insignificant. This is due to the distance from the Class 1 area and magnitude and characteristics of emission sources at Duke Energy' project site.

Additional Analysis Conclusions

Finally, the results of the additional impact analysis conclude the operation of the facility will have no significant impact on economic growth, soils, vegetation, or visibility in the immediate vicinity or on any Class I area.

Part F – HAPs Analysis

This evaluation was originally performed in support on the initial permitting effort for the IGCC plant. Although the changes being proposed as part of the significant source modification request do not involve HAP emissions, the proposed physical changes to certain buildings, structures and source locations were conservatively viewed as having the potential to affect the results of the previous HAP analysis. Consequently, the HAP analysis was repeated for this permit evaluation. The results from the re-analysis were essentially the same as for the original analysis and are discussed below.

OAQ currently requests data concerning the emission of 189 HAPs listed in the 1990 Clean Air Act Amendments (CAAA) that are either carcinogenic or otherwise considered toxic and may be used by industries in the State of Indiana. These substances are listed as air toxic compounds on the State of Indiana, Department of Environmental Management, Office of Air Quality's construction permit application Form GSD-08.

Potential emissions of aggregate HAPs from Duke Energy’s IGCC plant are estimated to be 13.81 tons per year.

A full HAP analysis was completed for Duke Energy's project comparing the maximum estimated concentrations of each pollutant with the Unit Risk Factor (URF) or Inhalation Unit Risk and the Reference Concentration (RfC). This analysis offers a refined, up to date site specific analysis that takes into account the different potencies and health effects that each pollutant presents to the public.

The Unit risk factor (URF) is the upper-bound excess lifetime cancer risk estimated to result from continuous inhalation exposure to a pollutant over a 70 year lifetime. Multiplying the estimated concentration by the URF will produce a cancer risk estimate. The cancer risk estimate is the conservative probability of developing cancer from exposure to a pollutant or a mixture of pollutants over a 70 year lifetime, usually expressed as the number of additional cancer cases in a given number of people, e.g., one in a million. For screening purposes at Duke Energy's project site, the cancer risk estimates for each pollutant are considered to be additive when deriving the cumulative maximum individual cancer risk.

Non-cancer health effects are determined using the Reference Concentration (RfC). The RfC is an estimate of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. Dividing the estimated pollutant concentration by the RfC will determine the pollutant's Hazard Quotient (HQ). All of the HAPs' Hazard Quotients were added together to determine the Hazard Index (HI) for Duke Energy's project.

This HAP screening analysis uses health protective assumptions that overestimate the actual risk associated with emissions from Duke Energy's proposed IGCC plant. Estimates 1) assume a 70 year exposure time, 2) assume that all carcinogens cause the same type of cancer, 3) assume that all non-carcinogens have additive health effects, 4) assume maximum permit allowable emissions from the facility, and 5) use conservatively derived dose-response information. The risk analysis cannot accurately predict whether there will be observed health problems around Duke Energy's project site; rather it identifies possible avenues of risk.

The results of the HAP modeling are in Table 7.

TABLE 7
Hazardous Air Pollutant Modeling Results

	Potential Emissions	**Annual Concentration**	**Cancer**	**Cancer Risk**	**Non-Cancer**	**Hazard Quotient**
Compound	**Tons per Year**	**(ug/m3)**	**URF, (ug/m3)-1**		**Chronic RfC, ug/m3**	
Formaldehyde	5.95	1.17E-02	5.5E-09	6.6E-11	9.80	0.004
n-Hexane	1.74	3.07E-02			200.00	0.000
Toluene	4.94	6.22E-02			400.00	0.000
Xylenes	1.18	2.08E-03			100.00	0.000
Total HAPS	13.81		**Total Cancer Risk**	**6.6E-11**	**Hazard Index**	**0.0015**

* Further information on URFs and RfCs can be found at the following EPA website: http://www.epa.gov/ttn/atw/toxsource/chronicsources.html

The Hazard Index for the project does not exceed 1. Pollutants with a Hazard Quotient (HQ) greater than 1 are considered to be at concentrations that could represent a health concern. Hazard Quotients above 1 do not represent areas where adverse health effects will be observed but indicate that the potential exists.

The additive cancer risk estimate from all HAPs is well below one additional cancer cases in one million people. The US EPA considers one in ten thousand (1.0E-04) excess cancer risks to be the upper range of acceptability with an ample margin of safety. The probability for the general public to be exposed to these HAPs for 24 hours a day, seven days a week, 52 weeks a year for 70 years is minimal.

Part H - Summary of Air Quality Analysis

As discussed above a re-evaluation of potential impacts on PM10 and CO air quality was performed in support of the proposed significant source modification request. The outcome of that re-evaluation was very similar to the original evaluation and demonstrated that no adverse impact to human health or welfare would occur.

Malcolm Pirnie prepared the modeling portion of the PSD application. Knox County is designated as attainment for all criteria pollutants. VOCs, PM_{10}, NO_2, SO_2, and CO emission rates associated with the proposed facility exceeded the respective significant emission rates. Modeling results taken from the latest version of the AERMOD model showed CO, PM_{10}, SO_2, and NO_2 impacts were predicted to be greater than the significant impact levels. Duke Energy did trigger the preconstruction monitoring threshold level for CO, $PM_{10,}$ and SO_2 but can satisfy the preconstruction monitoring requirement since there is existing air quality monitoring data representative of the area. The NAAQS and increment modeling for CO, PM_{10}, NO_2, and SO_2 showed no violations of the standards. The nearest Class I area is Mammoth Cave National Park in Kentucky over 200 kilometers away from the source. An additional impact analysis was required but the operation of the proposed facility will have no significant impact. A Hazardous Air Pollutant (HAP) analysis was performed and showed no likely adverse impact.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

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SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Mack Sims
Duke Energy Indiana, Inc - Edwardsport Generating Station
1000 E. Main St
Plainfield, IN 46168

DATE: March 1, 2010

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

SUBJECT: Final Decision
Significant Source Modification
083-28683-00003

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:
Jack L. Stutz (GM - Regulated Fossil Ops)
James Gislason (Risk Management Consultants)
Tony Schroeder (Trinity Consultants)
Steven Frey (Malcolm Prinie, Inc)
Patrick Coughlin (Duke Energy Indiana, Inc)
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

IDEM
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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March 1, 2010

TO: Knox County Public Library

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

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: Duke Energy Indiana, Inc - Edwardsport Generating Station

Permit Number: 083-28683-00003

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

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: March 1, 2010

RE: Duke Energy Indiana, Inc - Edwardsport Generating Station / 083-28683-00003

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

In order to conserve paper and reduce postage costs, IDEM's Office of Air Quality is now sending many permit decisions on CDs in Adobe PDF format. The enclosed CD contains information regarding the company named above.

This permit is also available on the IDEM website at:
http://www.in.gov/ai/appfiles/idem-caats/

If you would like to request a paper copy of the permit document, please contact IDEM's central file room at:

Indiana Government Center North, Room 1201
100 North Senate Avenue, MC 50-07
Indianapolis, IN 46204
Phone: 1-800-451-6027 (ext. 4-0965)
Fax (317) 232-8659

Please Note: *If you feel you have received this information in error, or would like to be removed from the Air Permits mailing list, please contact Patricia Pear with the Air Permits Administration Section at 1-800-451-6027, ext. 3-6875 or via e-mail at PPEAR@IDEM.IN.GOV.*

Enclosures
CD Memo.dot 11/14/08

Mail Code 61-53

IDEM Staff	MDENNEY 3/1/2010 Duke Energy Indiana, Inc. – 083-28683-00003 (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**	

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1		Mack Sims Duke Energy Indiana, Inc. - Edwardsport Generating 1000 E Main St Plainfield IN 46168 (Source CAATS) – VIA CONFIRMED DELIVERY									
2		Jack L Stultz GM - Regulated Fossil Ops Duke Energy Indiana, Inc. - Edwardsport Generating c/o M Sims, 1000 E Main St Plainfield IN 46168 *(RO CAATS)*									
3		Mr. Ron Clark 4476 N. American Rd Bicknell IN 47512 *(Affected Party)*									
4		Mr. Randy Brown Plumbers & Steam Fitters Union, Local 136 2300 St. Joe Industrial Park Dr Evansville IN 47720 *(Affected Party)*									
5		Mr. Larry Kane Bringham, Summers, Welsh & Spilman 10 West Market Street, Suite 2700 Indianapolis IN 46204 *(Affected Party)*									
6		Mr. Kerwin Olson Citizens Action Coalition 603 E Washington St Ste 502 Indianapolis IN 46204 *(Affected Party)*									
7		Knox County Health Department 520 S. 7th Street Vincennes IN 47591-1038 *(Health Department)*									
8		Knox Co Public Library 502 N 7th St Vincennes IN 47591-2101 *(Library)*									
9		Knox County Commissioners 3886 S Middle Hart Street Vincennes IN 47591 *(Local Official)*									
10		Edwardsport Town Council P.O. Box 142 Edwardsport IN 47528 *(Local Official)*									
11		Mr. David C. Bender McGillivray Westerberg & Bender LLC 305 S Paterson St Madison WI 53703 *(Affected Party)*									
12		Joanne Alexandrovich Vanderburgh County Health Dept. 420 Mulberry ST. Evansville IN 47713 *(Affected Party)*									
13		Gordon Gray Excelsior Energy 11100 Wayzata Blvd, Suite 305 Minnetonka MN 55305 (Affected Party)									
14		Ms. Isabel Piedmont Bloomington City Council 819 S. Washington Street Bloomington IN 47401 *(Affected Party)*									
15		John & Joann Hoadley 1070 W Jefferson Street Franklin IN 46131-2179 *(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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1		Richard President SAVE THE VALLEY INC 3800 W H&H RUSTIC LANE PO BOX 813 MADISON IN 47250 (Affected Party)									
2		Ms. Jennifer Nulph 1023 Franklin Street Columbus IN 47201 *(Affected Party)*									
3		Andreas Witzel 1543 Broadway Street Indianapolis IN 46202 *(Affected Party)*									
4		Ms. Brenda Bragg 1025 Franklin Street Columbus IN 47201 *(Affected Party)*									
5		Ms. Martha Jane Neufelder 1402 Chestnut Street Columbus IN 47201 *(Affected Party)*									
6		Mr. Mark Hill City of Vincennes - Common Council 203 Vigo Street Vincennes IN 47591 *(Affected Party)*									
7		Mr. Willard Freeman 7839 Bellsville Pike Nashville IN 47448 *(Affected Party)*									
8		Mr. Matthew Schaefer 1347 North Park Avenue Indianapolis IN 46202 *(Affected Party)*									
9		Ms. Deborah Quinto 6337 Macatuck Drive Indianapolis IN 46220 *(Affected Party)*									
10		Mrs. Amanda Figolah 11195 Catalina Drive Fishers IN 46038 *(Affected Party)*									
11		Mr. Arthur Ross, Sr. 5928 South 75 West Ferdinand IN 47532 *(Affected Party)*									
12		Mr. Tom Duncan 6146 Ralston Avenue Indianapolis IN 46220 *(Affected Party)*									
13		Mr. Douglas Hatton 15290 Nashua Circle Westfield IN 46074 (Affected Party)									
14		Kevin & Elizabeth Curtis 816 West Fourth Street Bicknell IN 47512 *(Affected Party)*									
15		Ms. Linda Joyner 8261 Redondo Drive Indianapolis IN 46236 *(Affected Party)*									

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1		John State Senator State of Indiana 200 West Washington Street Indianapolis IN 46204 (Legislator)									
2		Mr. Greg Deaves Sherwinn Williams #1211 2704 Hart Street Vincennes IN 47591-9234 *(Affected Party)*									
3		Ms. Yvonne Wittman 1917 East Arden Drive Bloomington IN 47401 *(Affected Party)*									
4		Daniel McCrary 116 Main St Bicknell IN 47512 *(Affected Party)*									
5		Ann Patton 608 Indiana St Bicknell IN 47512 *(Affected Party)*									
6		Mr. Georg Karl First Church of God in Vincennes 342 N Hyde Park Drive Vincennes IN 47591 *(Affected Party)*									
7		Bonnie Sydow 9491 N Freelandville Rd Edwardsport IN 47528 *(Affected Party)*									
8		Frank Gugliotta 515 W 8th St Bicknell IN 47512 *(Affected Party)*									
9		Mr. Vincent Griffin Environmental and Energy Policy 115 West Washington Street Suite # 850 S. Indianapolis IN 46204 *(Affected Party)*									
10		Mark Blackwell PO Box 36 Edwardsport IN 47528 *(Affected Party)*									
11		Jen Holscher 207 E Shipping St Edwardsport In 47528 *(Affected Party)*									
12		James Parish 924 N 9th Vincennes IN 47591 *(Affected Party)*									
13		Casey Robbins 9344 E Pepmeier Rd Oaktown IN 47561 (Affected Party)									
14		Steven Fields PO Box 237 Edwardsport IN 47528 *(Affected Party)*									
15		Tim Ellerman 1660 Lost Rd Monroe City In 47557 *(Affected Party)*									

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1		Henry 13 W Swartzel Vincennes In 47591 (Affected Party)									
2		Carl Koraleski 1811 Woodlawn Dr Washington In 47501 *(Affected Party)*									
3		Corey Williams 307 W Jackson St Edwardsport In 47528 *(Affected Party)*									
4		Don Hart 4 Robert Dr Bicknell In 47512 *(Affected Party)*									
5		Jeanna Cummings PO Box 61 Edwardsport IN 47528 *(Affected Party)*									
6		George Hassell 302 S 4th St PO Box 102 Edwardsport In 47528 *(Affected Party)*									
7		Clint Jochim 604 S Main St Bicknell In 47512 *(Affected Party)*									
8		James Sweeney 417 W 5th Bicknell IN 47591 *(Affected Party)*									
9		Russell Buck 15457 E ST RD 358 Edwardsport IN 47528 *(Affected Party)*									
10		Gerald Hill 911 Popcorn Rd Springville In 47462 *(Affected Party)*									
11		Clark Anderson PO Box 101 Westphalia IN 47596 *(Affected Party)*									
12		Andrew Moreland 406 S Main Bicknell IN 47512 *(Affected Party)*									
13		Emily Heineke 609 N 5th St Vincennes IN 47591 (Affected Party)									
14		Scott Brown PO Box 447 Vincennes In 47591 *(Affected Party)*									
15		Dee Johnson PO Box 74 Nineveh In 46164 *(Affected Party)*									

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1		Robert 310 Plumtree Vincennes In 47591 (Affected Party)									
2		Al Baldwin 1402 Old Orchard Place Vincennes In 47591 *(Affected Party)*									
3		Marc McNeece 608 N 6th Vincennes In 47591 *(Affected Party)*									
4		James Newkirk PO Box 61 Edwardsport In 47528 *(Affected Party)*									
5		Gary Gentry PO Box 246 Newburgh IN 47629 *(Affected Party)*									
6		P. R. Sweeney 2899 S Hickory Cr Rd Vincennes In 47591 *(Affected Party)*									
7		Patrick Fazio PO Box 299 Terre Haute In 47808 *(Affected Party)*									
8		Mr. Kent Hert RR1 BOX 192 Springville IN 47462 *(Affected Party)*									
9		Ms. Linda Montag-Olson 6495 Glenwood Drive Zionesville IN 46071 *(Affected Party)*									
10		Mr. Carl Lowry 16947 Cimarron pass Noblesville IN 46060 *(Affected Party)*									
11		Mr. Brad Severance 6443 Bayside North Indianapolis IN 46250 *(Affected Party)*									
12		Jane Goodman 715 W 13th St Bloomington IN 47408 *(Affected Party)*									
13		Susan Bookout 3723 Tamarron Dr Bloomington In 47408 (Affected Party)									
14		Matt Zink 100 Town Hill Rd Nashville In 47448 *(Affected Party)*									
15		Ken Pimple 1007 S Washington St Bloomington In 47401 *(Affected Party)*									

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1		Lynn 1730 S 950 E Zionsville In 46077 (Affected Party)									
2		Debra Spratt 12637 Duval Dr Fishers In 46037 *(Affected Party)*									
3		Karen Dopkins 12625 Valhalla Lane Fishers In 46037 *(Affected Party)*									
4		Thomas & Beth Hollingsworth 2321 E Rechter Rd Bloomington In 47401 *(Affected Party)*									
5		Angela Lexmond 1302 S Henderson Bloomington In 47401 *(Affected Party)*									
6		Anne & Christopher Haynes 626 N Grandview Dr Bloomington IN 47408 *(Affected Party)*									
7		Jennifer Livesay 1007 S Washington St Bloomington In 47401 *(Affected Party)*									
8		Armin Moczek 1800 Windsor Dr Bloomington In 47401 *(Affected Party)*									
9		Mary Andrus-Overly 2212 Queens Way Bloomington In 47401 *(Affected Party)*									
10		Beckie Wagner 4100 S Rockport Rd Bloomington In 47403 *(Affected Party)*									
11		Stiphani & Tom Wilson 502 W 13th Bloomington In 47404 *(Affected Party)*									
12		Edwin & Monica Jensen 3432 N Valleyview Dr Bloomington In 47404 *(Affected Party)*									
13		Mary Beth OBrien 100 Town Hill Rd Nashville In 47448 (Affected Party)									
14		Shain Woodbury 2209 Laurelwood Dr Bloomington In 47401 *(Affected Party)*									
15		Silja Weber 620 W Howe St Apt A Bloomington In 47403 *(Affected Party)*									

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1		Dorothy & Steven 409 E Clover Lane Bloomington In 47408 (Affected Party)									
2		Jason Hill 210 W 14th St Bloomington In 47404 *(Affected Party)*									
3		Velda Kanne PO Box 2174 Bloomington In 47402-2174 *(Affected Party)*									
4		Cynthia Schultz 1643 E Maplecrest Dr Bloomington In 47408 *(Affected Party)*									
5		Marcia Veldman 6181 Kent Rd Bloomington In 47401 *(Affected Party)*									
6		Michael Fischer 6344 Kingsley Dr Indianapolis In 46220 *(Affected Party)*									
7		Peter & Carolyn Mitchell 6412 Wellston Drive Bloomington IN 47408 *(Affected Party)*									
8		Mary Blizzard 1510 E Maxwell Lane Bloomington In 47401 *(Affected Party)*									
9		Kim Sakmann 8700 E St Road 45 Unionville IN 47468 *(Affected Party)*									
10		Chris Judge 3611 Bainbridge Road Bloomington IN 47401 *(Affected Party)*									
11		John Thompson Clean Air Task Force 231 W Main Suite 1E Carbondale IL 62901 *(Affected Party)*									
12		Mary Meyer Indiana Green Party PO BOX 441105 Indianapolis IN 46244 *(Affected Party)*									
13		David Pilbrow 3308 Ivory Way Indianapolis In 46227 (Affected Party)									
14		Martha Sattinger 4333 E Stephens Dr Bloomington In 47408 *(Affected Party)*									
15		Laura Mojonnier 1800 E Windsor Drive Bloomington IN 47401 *(Affected Party)*									

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1		Jeanette 4980 W 59th Street Indainapolis IN 46254 (Affected Party)									
2		Mr. David Keppel 1308 North Maple Street Apt #22 Bloomington IN 47404-3367 *(Affected Party)*									
3		H. Jane Sandberg 2201 N Fritz Drive Bloomington IN 46204-2251 *(Affected Party)*									
4		Mr. Greg Foote 6199 Norwaldo Avenue Indianapolis IN 46220 *(Affected Party)*									
5		Valerie Boots 5215 E 72nd Street Indianapolis IN 46250 *(Affected Party)*									
6		Marilyn Bedford 9222 Garrison Drive Apt 303-B Indianapolis IN 46240 *(Affected Party)*									
7		Ms. Elizabeth Page 7145 Franklin Parke Boulevard Indianapolis IN 46259-5723 *(Affected Party)*									
8		Mr. Jim Sweeney 1773 Selo Drive Schererville IN 46372 *(Affected Party)*									
9		Joan Keeler 412 E Cardinal Drive Bloomington IN 47401 *(Affected Party)*									
10		DEBORAH ALLMAYER INDIANA UNIVERSITY 2711 E 10TH ST BLOOMINGTON IN 47408 *(Affected Party)*									
11		ARLIS BATES 936 VANDALIA ST HILLSBORO IL 62049 *(Affected Party)*									
12		Mr. TERRANCE BLACK GREEN WAY SUPPLY 620 N DELEWARE ST INDIANPOLIS IN 46204 *(Affected Party)*									
13		Mr. John Blair 800 Adams Ave Evansville IN 47713 (Affected Party)									
14		Mr. Greg Buck Campaign for Sustainable Economics 537 Fletcher Ave #2 Indianapolis IN 46203 *(Affected Party)*									
15		Mr. Greg Cardinal First American Bank PO BOX 1317 Vincennes IN 47591 *(Affected Party)*									

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1		James H. Risk Management Consultants 111 Hendron Hills Dr Vincennes IN 47591 (Consultant)									
2		Mary Helfer 936 Vandalia St Hillsboro IL 62049 *(Affected Party)*									
3		Mr. Douglas Halton 15290 Nashua Cir Westfield IN 46074 *(Affected Party)*									
4		Mr. Richard Helton Vincennes University 1002 N First St Vincennes IN 47591 *(Affected Party)*									
5		Mr. A. John Hidde 507 Eastgate Drive Vincennes IN 47591 *(Affected Party)*									
6		Mrs. Judith Hostetler 6315 E Pleasant Run Pkwy South Dr Indianapolis IN 46219 *(Affected Party)*									
7		Gary and Heliene Houdak 7111 Williams Creek Dr Indianapolis IN 46240 *(Affected Party)*									
8		Mr. Phil Hoy 200 West Washington Street Indianapolis IN 46204 *(Affected Party)*									
9		Anne Jacoby Generations 1019 N 4th St PO BOX 314 Vincennes IN 47591 *(Affected Party)*									
10		Elizabeth Joshi 2377 Lakeridge Dr Newburgh IN 47630 *(Affected Party)*									
11		Tim Kiger Schoot North America 2000 Chestnut St Vincennes IN 47591 *(Affected Party)*									
12		Grey Larson 917 W Howe St Bloomington IN 47403 *(Affected Party)*									
13		Mr. Terry Mooney City of Vincennes 201 Vigo St Vincennes IN 47591 (Affected Party)									
14		Tammy J. Orahood 2417 Shadow Grove Ct Bloomington IN 47401 *(Affected Party)*									
15		Kevin Rowland Stradtner, Rowland & Associates 518 Main St Vincennes IN 47591 *(Affected Party)*									

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1		Tony Trinity Consultants 1717 Dixie Hwy Ste 900 Covington KY 41011 (Consultant)									
2		Helen Seirp Regional President Old National Bank PO BOX 1200 Vincennes IN 47591 *(Affected Party)*									
3		Terry Singleton 4249 Sunrise Dr Sellersburg IN 47172 *(Affected Party)*									
4		Timothy Smith Vincennes Twp Fire Dept 1265 S Hart St Rd Vincennes IN 47591 *(Affected Party)*									
5		J. Wayne Thomann Kemper CPA Group. LLC 505 N 6th Street P O Box 297 Vincenness IN 47591 *(Affected Party)*									
6		Fred E. Thompson Knox County Commissioner 4315 N Camp Arthur Road Bruceville IN 47516 *(Affected Party)*									
7		Kent E. Utt Community Bank President, Region Bank 2202 N 6th Street Vincenness IN 47591 *(Affected Party)*									
8		Tim Wilson 1260 Thornton Court Apt. D Columbus IN 47201 *(Affected Party)*									
9		Greg Wolters Schott North America 2000 Chestnut Street Vincenness IN 47591 *(Affected Party)*									
10		Nicole Robinson MPR Associates 320 King Street, Suite 400 Alexandria VA 22314 *(Affected Party)*									
11		Mr. Patrick Coughlin Duke Energy Indiana, Inc. 1000 East Main Street Plainfield IN 46168 *(Source ? addl contact)*									
12		Mr. Steven Frey Malcolm Pirnie, Inc 1515 East Woodfield Road Suite 360 Schaumburg IL 60173 *(Consultant)*									
13		Violet Lehrer Sierra Club 85 Second St, 2nd Floor San Francisco CA 94105 (Affected Party)									
14		Rex Alton 2341 S Old Decker Rd Vincennes IN 47591 *(Affected Party)*									
15		Zac Elliot Citizens Action Coalition of Indiana 603 E Washington St # 502 Indianapolis IN 46204 *(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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Mail Code 61-53

<table>
<tr><td>IDEM Staff</td><td colspan="3">MDENNEY 3/1/2010
Duke Energy Indiana, Inc. – 083-28683-00003 (final)</td><td rowspan="2">AFFIX STAMP
HERE IF
USED AS
CERTIFICATE
OF MAILING</td></tr>
<tr><td>Name and address of Sender</td><td>▶</td><td>Indiana Department of Environmental Management
Office of Air Quality – Permits Branch
100 N. Senate
Indianapolis, IN 46204</td><td>Type of Mail:

CERTIFICATE OF MAILING ONLY</td></tr>
</table>

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		Steve 203 Nicholas St Vincennes IN 47591 (Affected Party)									
2											
3											
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5											
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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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