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

*Mitchell E. Daniels, Jr.*
*Governor*

*Thomas W. Easterly*
*Commissioner*

100 North Senate Avenue
Indianapolis, Indiana 46204
MC 61-53
(317) 232-8603
(800) 451-6027
www.IN.gov/idem

TO: Interested Parties / Applicant

DATE: January 25, 2008

RE: Duke Energy Indiana, Inc - Edwardsport Generating Station / 083-23529-00003

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

# Notice of Decision: Approval - Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the enclosed matter. Pursuant to IC 13-15-5-3, this permit is effective immediately, unless a petition for stay of effectiveness is filed and granted according to IC 13-15-6-3, 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 and IC 13-15-6-1 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204, **within eighteen (18) calendar 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.

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
FNPER.dot12/03/07

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100 North Senate Avenue
MC 61-53, Room 1003
Indianapolis, Indiana 46204-2251
(317) 232-8603
(800) 451-6027
www.IN.gov/idem

Mr. Mack Sims
Duke Energy Indiana
1000 East Main Street
Plainfield, IN 46168

January 25, 2008

Re: 083-23529-00003
Significant Source Modification to:
Part 70 Operating Permit No.: T 083-7243-00003

Dear Mr. Sims:

Duke Energy Indiana was issued Part 70 Operating Permit T083-7243-00003 on August 10, 2004, for an electric generating plant. An application to modify the source was received on August 10, 2006, and additional information was received on July 9, 2007. Pursuant to 326 IAC 2-7-10.5 the following emission units are approved for construction at the source:

(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)** | |
|---|---|
| **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, 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.

(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.

(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.

The following construction conditions are applicable to the proposed project:

General Construction Conditions

1. The data and information supplied with the application shall be considered part of this source modification approval. Prior to any proposed change in construction which may affect the potential to emit (PTE) of the proposed project, the change must be approved by the Office of Air Quality (OAQ).

2. This approval to construct does not relieve the permittee of the responsibility to comply with the provisions of the Indiana Environmental Management Law (IC 13-11 through 13-20; 13-22 through 13-25; and 13-30), the Air Pollution Control Law (IC 13 17) and the rules promulgated thereunder, as well as other applicable local, state, and federal requirements.

Effective Date of the Permit

3. Pursuant to IC 13-15-5-3, this approval becomes effective upon its issuance.

4. Pursuant to 326 IAC 2-1.1-9 and 326 IAC 2-7-10.5(i), the Commissioner may revoke this approval if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is suspended for a continuous period of one (1) year or more.

5. 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.

6. Pursuant to 326 IAC 2-7-10.5(l) the emission units constructed under this approval shall not be placed into operation prior to revision of the source's Part 70 Operating Permit to incorporate the required operation conditions.

This significant source modification authorizes construction of the new emission units. Operating conditions shall be incorporated into the Part 70 operating permit as a significant permit modification in accordance with 326 IAC 2-7-10.5(l)(2) and 326 IAC 2-7-12. Operation is not approved until the significant permit modification has been issued.

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 Kimberly Cottrell, OAQ, 100 North Senate Avenue, MC 61-53, Room 1003, Indianapolis, Indiana, 46204-2251, or call at (800) 451-6027, and ask for Kimberly Cottrell or extension (3-0870), or dial (317) 233-0870.

Sincerely/Original Signed By:

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

Attachments:
Updated Permit
Technical Support Document
PTE Calculations

klc

cc: File – Knox County
Knox County Health Department
U.S. EPA, Region V
Southwest Regional Office
Air Compliance Inspector – Dan Hancock
Compliance Data Section
Permit Reviewer – Iryn Calilung
Permits Administration and Development
Office of Legal Counsel

Station Manager, Edwardsport Generating Station
c/o Mr. Patrick Coughlin
Duke Energy Indiana
1000 East Main Street
Plainfield, IN 46168

Steven Frey, Associate
Malcolm Pirnie, Inc.
1515 East Woodfield Road, Suite 360
Schaumburg, IL 60173

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# PART 70 OPERATING PERMIT
# 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.

| Operation Permit No.: T083-7243-00003 | |
|---|---|
| Issued by: Original Signed by<br>Janet G. McCabe, Assistant Commissioner<br>Office of Air Quality | Issuance Date: August 10, 2004<br>Expiration Date: August 10, 2009 |

First Significant Permit Modification T083-17006-00003, issued June 7, 2006

| Significant Source Modification No.: T083-23529-00003 | Pages Affected: Entire Permit |
|---|---|
| Issued by/Original Signed By:<br>Matthew Stuckey, Deputy Branch Chief<br>Permits Branch<br>Office of Air Quality | Issuance Date:January 25, 2008 |

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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<br>Major Source, under PSD Rules<br>Major Source (Existing Plant), Section 112 of the Clean Air Act<br>Minor Source (IGCC Plant), Section 112 of the Clean Air Act<br>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, 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.

(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.

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

D.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.)

**<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. 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 $C = 50\ \square/m^3$
$Q$ = 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.)

**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. 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<br>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<br>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<br>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<br>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<br>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<br>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<br>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<br>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<br>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<br>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<br>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<br>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<br>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<br>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<br>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<br>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<br>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 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.

(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.

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

D.10.1 Material Handling and Lime Handling Baghouse BACT Requirements [326 IAC 2-2]

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, lime handling operations exhausting to 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 shall not exceed a grain loading of 0.003 grains per dry standard cubic feet (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)

D.10.2 Particulate Matter Emissions [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 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 |

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 for PM control shall be in operation and control emissions at all times the associated coal drop points, receiving and unloading, grinding mill and lime facilities are in operation.

(b) Vendor guarantee that each baghouse 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 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-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 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 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, 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 lime 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, 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 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 used in conjunction with the coal drop points, receiving and unloading station, grinding mill and lime 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) 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 exhausts, railcar unloading stations and all response steps taken and the outcome for each.

(b) To document compliance with Condition D.10.7 - Baghouse Parametric Monitoring, the Permittee shall maintain records of the pressure drop across each baghouse.

(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.)

**<u>Emission Units at the Existing Coal-Fired Power Plant to be Retired prior to operation of the IGCC Plant:</u>**

(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 $SO_2$emission limit (ng/J heat input),

%Ps = Percentage of potential $SO_2$emission 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 $SO_2$in 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 $SO_2$in excess of either:

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

(ii) 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 $SO_2$in 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 $SO_2$in 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 $20 \times 10^{-6}$ 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 $SO_2$emissions, 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 $SO_2$control 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 $SO_2$emissions in place of a continuous $SO_2$emission monitor at the inlet to the $SO_2$control 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.

$$E_{avg} = \frac{\sum_{i=1}^{12}\left(ER_i \times n_i\right)}{\sum_{i=1}^{12} n_i} \qquad \text{(Eq. 10)}$$

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.
.

(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, 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)]

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.)

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)]

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 | |
| 60.13, Monitoring requirements | Yes | |
| 60.14, Modification | Yes | |
| 60.15, Reconstruction | Yes | |

| Subpart A reference | Applies to Subpart OOO | Comment |
|---|---|---|
| 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 $2.84 \times 10^7$ 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 $CO_2$or $O_2$concentration, 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 $CO_2$concentration or the minimum potential $O_2$concentration (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.

$1.912x10^{-3}$ = 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 | Model year(s) | 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) | | |
|---|---|---|---|---|
| | | $NO_X$ + 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<br>2009+ \3\ | 10.5 (7.8)<br>4.0 (3.0) | 3.5 (2.6) | 0.54 (0.40)<br>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 |

the inlet and outlet of the control device; | or 3B of 40 CFR part 60, appendix A. | to determine $O_2$ concentration must be made at the same time as the measurements for $NO_X$ 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) Measurements to determine moisture content must be made at the same time as the measurements for $NO_X$ concentration.

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) $NO_X$ concentration must be at 15 percent $O_2$, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

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) If using a control device, the sampling site stationary CI internal combustion engine exhaust.

number of traverse points;

must be located at the outlet of the control device.

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) Measurements to determine $O_2$ concentration must be made at the same time as the measurement for $NO_X$ 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, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17).

(c) Measurements to determine moisture content must be made at the same time as the measurement for $NO_X$ concentration.

iv. Measure $NO_X$ at the exhaust of the stationary internal combustion engine.

(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

(d) $NO_X$ concentration must be at 15 percent $O_2$, dry basis. Results of this test consist of the average of the three 1-hour 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

| | | | |
|---|---|---|---|
| | | | of the average of the three 1-hour or longer runs. |
| 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. | (a) If using a control device, the sampling site must be located at the outlet of the control device. |
| | 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) Measurements to determine $O_2$ concentration must be made at the same time as the measurements for PM 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) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration. |
| | iv. Measure PM at the exhaust of the stationary | (4) Method 5 of 40 CFR part 60, appendix A. | (d) PM concentration must be at 15 |

internal percent
$O_2$, dry
combustion engine.
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.<br><br>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)<br>• 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<br>• 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<br>Describe:<br><br>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.<br><br>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

Attachment A – Fugitive Dust Control Plan
Prevention of Significant Deterioration (PSD)
Part 70 Operating Permit No. T 083-7243-00003

## Source Background and Description

| | |
|---|---|
| Source Name: | Duke Energy Indiana – Edwardsport Generating Station |
| Source Location: | 15424 East State Road 358, Edwardsport, Indiana 47258 |
| County: | Knox |
| SIC Code: | 4911 |
| Operation Permit No.: | T 083-7243-00003 |
| Operation Permit Issuance Date: | August 10, 2004 |
| Significant Source Modification No.: | SSM 083-23529-00003 |
| Significant Permit Modification No.: | SPM 083-23531-00003 |
| Permit Reviewer: | Kimberly Cottrell |

## Introduction

The following control plan, when implemented, is designed to reduce fugitive dust emissions of $PM/PM_{10}/PM_{2.5}$ from:

(a) Paved roads and parking areas

(b) Coal/slag piles

such that visible emission limitations specified in the permit are met.

The plan shall be implemented on a year-round basis until such time as another plan is approved or ordered by the Indiana Department of Environmental Management.

The name, title and telephone number of the person who is responsible for implementing the plan will be supplied to the OAQ Compliance Section.

## Paved Roads and Parking Areas

Paved roads and parking areas shall be controlled by the use of removal of deposits on roadways, speed limitation on vehicle traffic and wet suppression techniques as needed. Speed limits on paved roads shall be posted to be 20 mph. Incidents of material spillage on paved roads that may create fugitive dust shall be investigated and properly cleaned up.

Cleaning of paved road segments and parking areas may be delayed by one day when:

(a) 0.1 or more inches of rain have accumulated during the 24-hour period prior to cleaning'

(b) The road segment is closed or abandoned. Abandoned roads will be barricaded to prevent vehicle access.

(c) It is raining at the time of the scheduled cleaning.

(d) Ambient air temperature is below $32^0$F.

## Coal and Slag Piles

Coal and slag piles shall be sprayed with water, on an "as-needed" basis to eliminate wind erosion and not exceed the visible emission limitations in the permit. Water added to slag during processing provides added control. Compaction techniques on coal will be used to further control PM.

## Monitoring and Record Keeping

Records shall be kept of the removal of deposits and wet suppression application frequency and amount. Records shall be kept at the designated plant location for a minimum of five years and shall be available for inspection or copying upon request.

## Compliance Schedule

This plan shall be fully implemented when the IGCC facility commences operation.

# Indiana Department of Environmental Management
# Office of Air Quality

## Addendum to the Technical Support Document (TSD)
## 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 Road 358, Edwardsport, Indiana 47258 |
| County: | Knox |
| SIC Code: | 4911 |
| Operation Permit No.: | T 083-7243-00003 |
| Operation Permit Issuance Date: | August 10, 2004 |
| Significant Source Modification No.: | SSM 083-23529-00003 |
| Significant Permit Modification No.: | SPM 083-23531-00003 |
| Permit Reviewer: | Kimberly Cottrell |

### Public Notice Information

On November 18, 2007, the Office of Air Quality (OAQ) had a notice published in the *Sun-Commercial* in Vincennes, Indiana, stating that Duke Energy Indiana had applied for a significant modification to the Part 70 Operating Permit for the Edwardsport Generating Station issued on August 10, 2004, to install an integrated gasification combined cycle (IGCC) electric generating plant. 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 to provide comments on whether or not this permit should be issued as proposed, that a public meeting and hearing was scheduled for December 20, 2007, and that the public comment period was extended until December 31, 2007.

On December 20, 2007, 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.

### Comments Received

OAQ received comments from the following people (and groups of people):

- United States Environmental Protection Agency (U.S. EPA)
- Duke Energy Indiana (Duke)
- Indiana State Senator, John M. Waterman
- Indiana State Representative, District 64, Kreg Battles
- Local Public Officials representing the cities of Vincennes, Edwardsport, and Bicknell
- Joanne Alexandrovich, Vanderburgh County Health Department
- John Thompson, Clean Air Task Force
- John Blair, Valley Watch, Inc.
- David Bender, representing Sierra Club, Valley Watch, and Citizen Action Coalition
- Business Owners located in the cities of Vincennes, Edwardsport, and Bicknell

- Indiana Citizens living near the vicinity of the facility in the cities of Vincennes, Edwardsport, and Bicknell
- Indiana Citizens living near the cities of Evansville, Bloomington, and Indianapolis

The comments are summarized in the subsequent pages, with IDEM's corresponding responses.

**Comments from US EPA Region 5**

OAQ received comments from Sam Portanova on behalf of the U.S. EPA Region 5. 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:

**EPA Comment 1:**

The table in Condition D.8.5(c) does not include a header to indicate which pollutants are represented in each column.

**IDEM Response 1:**

IDEM has corrected the table.

**EPA Comment 2:**

Startup/Shutdown Emissions:
D.7.1 and D.7.5: Plantwide $NO_X$ and $SO_2$ startup/shutdown limits. (261 tpy $NO_X$, 105 tpy $SO_2$)

D.8.5 and D.8.8: Gasification Block startup/shutdown limits.

D.9.7 and D.9.11: Power Block startup/shutdown limits.

Startup/Shutdown BACT for CO, PM, and VOC does not include control options or limits on duration or number of startup/shutdown events. To assure that BACT limits are utilized and the plant is not "continually" in a state of startup/shutdown, some type of startup/shutdown controls and/or limits on duration should be included in the permit.

BACT is in tons per year as follows:

| | CO | PM | VOC |
|---|---|---|---|
| Thermal Oxidizer | 6.8 | 0.65 | 0.43 |
| Flare | 72.9 | 4.3 | 0.58 |
| Gasification Preheaters | 5.5 | 0.5 | 0.3 |
| Auxiliary Boilers | 46.0 | 4.2 | 3.0 |
| Combustion Turbines | 250.8 | 18.5 | 48.5 |
| TOTAL: | 382 | 28.15 | 52.81 |

What is the basis for the annual BACT limits? BACT should be over the shortest practical time period with sufficient compliance provision to assure practical and continuous enforceability. Please explain how these limits accomplish that purpose.

$NO_X$, $SO_2$, CO, PM, and VOC listed emissions factors increase significantly when the number of startup/shutdown hours exceed 32 (see Conditions D.7.5, D.8.8, and D.9.11). How is this justified? How are emission factors for startup/shutdown defined, determined, verified, and (if necessary) adjusted?

**IDEM Response 2:**

Upon request, Duke Energy Indiana provided the following information explaining cold startup of the IGCC Plant from ambient conditions:

**SEQUENCE OF EVENTS – THERMAL OXIDIZER**

**Operations Associated with Device**:

- Acid gas removal
- Gas recycle operations
- Sulfur recovery unit
- Tail gas unit

**Overview**:

- Pounds per Event established for three cold startup operating phases: Phase 1, involving initial warm-up; Phase 2, involving startup of first sulfur recovery unit and tail gas unit; and Phase 3, involving startup of second sulfur recovery unit. A hot startup of an individual gasification train is described as a fourth operating phase.
- A cold startup event takes approximately 84 hours, while a total plant shutdown event would take around 48 hours. It is possible to have some variation in these events, thus the breakdown of lbs/event over 3 operating phases. A hot startup is a much shorter duration than a cold startup.
- Engineering analysis / estimates were made for each phase of the startup and shutdown events.

**More Detailed Description:**

The main equipment operations associated with a startup venting to the thermal oxidizer during each of the operating phases include:

**Phase 1**: Initial warm-up (duration typically 32 hours) – Thermal Oxidizer burners combusting natural gas and sulfur pit vapors.

**Phase 2**: startup of first sulfur recovery unit (SRU) and tail gas unit (typically occurring around hour 32 and lasting approximately 30 hours) – Tail gas from first SRU is vented while waiting for tail gas unit (TGU) to come online. Also includes tail gas from TGU while waiting for first gas recycle unit (GRU) to come online.

**Phase 3**: startup of second SRU (typically occurring around 62 hours and continuing for approximately 22 hours) – Tail gas from second SRU is vented while increasing load to TGU. Also includes tail gas from TGU while waiting for second GRU to come online.

**Hot Startup**: Emissions occurring during a hot startup of an individual gasification train involve a restart of the SRU and GRU for the train. (Duration typically 5 hours or less.) A hot startup does not require the use of a gasification preheater to bring the gasifier to operating temperature.

## SEQUENCE OF EVENTS – FLARE DEVICE

**Operations Associated with Device**:

- Low temperature gas cooling
- Acid gas removal
- Combustion Turbine

**Overview:**

- Pounds per event established for three cold startup operating phases: Phase 1, involving initial warm-up; Phase 2, in which syngas is vented prior to achieving combustion in first combustion turbine (CT); and Phase 3, in which syngas is vented prior to achieving combustion in the second CT. A hot startup of an individual gasification train described as a fourth operating phase.
- A cold startup event takes approximately 84 hours, while a total plant shutdown event would take around 48 hours. It is possible to have some variation in these events, thus the breakdown of lbs/event over 3 operating phases. A hot startup is a much shorter duration than a cold startup.
- Engineering analysis / estimates made for each individual hour of the startup and shutdown events

**More Detailed Description:**

The main equipment operations associated with a startup venting to the flare during each of the operating phases include:

**Phase 1**: Initial warm-up (duration typically 32 hours) – Flare burners combusting natural gas.

**Phase 2**: Syngas venting prior to achieving combustion in the first CT to come online. Venting acid gas for a period of time prior to first SRU coming online. (Typically extends between hours 32 and 62).

**Phase 3**: Syngas venting prior to achieving combustion in the second CT to come online. Also, venting acid gas prior to second SRU coming online. (Typically extends between hours 62 and end of the cold startup.)

**Hot Startup**: Emissions occurring during a hot startup of an individual gasification train involve venting of syngas prior to achieving combustion in the affected CT and venting acid gas prior to the affected SRU coming online. (Duration typically 5 hours or less.) A hot startup does not require the use of a gasification preheater to bring the gasifier to operating temperature.

## SEQUENCE OF EVENTS – COMBUSTION TURBINES

**Operations Associated with Device**:

- Combustion of syngas, natural gas, or a blend of 90% syngas and 10% natural gas

**Overview**:

- Pounds per event established for three cold startup operating phases: Phase 1, in which the combustion turbines (CTs) are dormant as the Gasification Block goes through initial warm-up; Phase 2, during which the first CT to come online burns natural gas while awaiting syngas availability; and Phase 3, during which the first CT transitions to syngas and the second CT is started on natural gas while awaiting syngas availability. A hot startup of an individual gasification train is described as a fourth operating phase.

- A cold startup event takes approximately 84 hours, while a total plant shutdown event would be around 48 hours. It is possible to have some variation in these events, thus the breakdown of lbs/event over 3 operating phases. A hot startup is a much shorter duration than a cold startup.
- Engineering analysis / estimates were made for each individual hour of the startup and shutdown events.

**More Detailed Description:**

The main equipment operations associated with a startup of the combustion turbines on syngas venting to atmosphere during each of the operating phases include:

**Phase 1**: Combustion turbines are dormant as the Gasification Block goes through its initial warm-up phase (typically takes 32 hours).

**Phase 2**: First CT starts and continues to operate on natural gas while awaiting availability of syngas (typically between 32 and 62 hours).

**Phase 3**: First CT transfers to syngas and second CT starts, and continues to operate, on natural gas while awaiting syngas availability, then transitions to syngas. (This phase typically extends between hour 62 and the end of startup operations.)

**Hot Startup**: Emissions occurring during a hot startup of an individual gasification train include emissions from affected CT as it transitions from natural gas to syngas and is brought up to required operating load (duration typically 5 hours or less). A hot startup does not require the use of a gasification preheater to bring the gasifier to operating temperature.

IDEM has revised all permit conditions related to startup and shutdown emissions. The revisions are largely formatting in nature, although more substantive changes involve the inclusion of hot start provisions and short-term emission limits for startup and shutdown events. Table formatting changes are only shown for the first table. The revised conditions are as follows:

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/year~~ **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/year~~ **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 ~~tons/year.~~ **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 |

| **Annual Startup and Shutdown Emission Limits** | | |
|---|---|---|
| **Equipment** | **$NO_X$ (tpy)** | **$SO_2$ (tpy)** |
| **Total** | 266.4 | ~~122.4~~ **122.44** |

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 & Shutdown Emission Factors – Gasification Thermal Oxidizer – Syngas**~~

| **Startup and Shutdown Emission Factors Gasification Thermal Oxidizer – Syngas** | | | | |
|---|---|---|---|---|
| **Equipment** | **Operating Phase** | ~~**Total Time***~~ (~~hrs~~ ~~**of event**~~) | **$NO_X$** (lbs) | **$SO_2$** (lbs) |
| **Startup Event~~s~~** | | | | |
| Thermal Oxidizer **– Syngas** | **Phase 1** | ~~< 32~~ | 6.27 | 0.032 |
| Thermal Oxidizer **– Syngas** | **Phase 2** | ~~≥ 32 to ≤ 62~~ | 184.13 | 293.8 |
| Thermal Oxidizer **– Syngas** | **Phase 3** | ~~≥ 63~~ | 191.9 | 789.8 |
| **Thermal Oxidizer – Syngas** | **Phase 4** | | **4.29** | **327.2** |
| Equipment Trip B to Thermal Oxidizer | **N/A** | ~~N/A~~ | 3.5 | 815.2 |
| Tail Gas Unit Trip to Thermal Oxidizer | **N/A** | ~~N/A~~ | 2.1 | 897.4 |
| **Shutdown Event~~s~~** | | | | |
| Thermal Oxidizer **– Syngas** | **Partial Plant (≤ 5 hrs)** | ~~≤ 5~~ | 6.9 | 51.6 |

| **Startup and Shutdown Emission Factors<br>Gasification Thermal Oxidizer – Syngas** | | | | |
|---|---|---|---|---|
| **Equipment** | **Operating Phase** | ~~**Total Time***~~<br>~~(hrs **of event**)~~ | **$NO_X$** (lbs) | **$SO_2$** (lbs) |
| Thermal Oxidizer **– Syngas** | **Entire Plant (> 5 hrs)** | ~~> 5~~ | 15.8 | 51.7 |

~~*Total Time for a specific Startup or Shutdown Event~~

| **Startup and Shutdown Emission Factors<br>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<br>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<br>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<br>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<br>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** |
| **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.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 and shutdowns~~ **startups, shutdowns, and trips** of the gasification block shall not exceed the following ~~tons per year~~ **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.

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<br>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<br>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<br>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 |
| **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<br>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** |

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) ~~Total Startup and Shutdown tons per year shall not exceed the following:~~ **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 |

| Annual Startup and Shutdown Emission Limits | | | |
|---|---|---|---|
| **Equipment** | **CO** (tpy) | **PM**[1] (tpy) | **VOC** (tpy) |
| **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.9.11~~ **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<br>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 |

| **Startup and Shutdown Emission Factors<br>Gasification Auxiliary Boiler – Natural Gas** | | | | |
|---|---|---|---|---|
| **Equipment** | **Operating Phase**[1] | **CO** (lbs) | **PM**[2] (lbs) | **VOC** (lbs) |
| 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<br>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<br>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** |
| **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** | **Duration typically runs from** |

| **Summary of Startup Phases<br>Gasification Combustion Turbines – Syngas** | | |
|---|---|---|
| **Phase** | **Combustion Turbines** | **Cold Start Timeline** |
| | **syngas combustion and startup of second CT on natural gas, then transitioning to syngas** | **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** |

**EPA Comment 3:**

Condition D.9.10 references $SO_2$ emissions from D.9.7. However, D.9.7 does not include $SO_2$ limits.

**IDEM Response 3:**

$SO_2$ emissions from the Power Block are addressed in Section D.7; therefore, Condition D.9.10 has been removed and the remaining conditions in Section D.9 have been renumbered.

~~D.9.10 Sulfur Dioxide Emissions [326 IAC 7-2-1(c)][326 IAC 2-7-5(3)(A)][326 IAC 3-5]~~

~~Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions from Stacks S-2a and S-2b does not exceed the limits specified in Conditions D.9.7- Sulfur Dioxide ($SO_2$), using a thirty (30) day rolling weighted average~~

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

**EPA Comment 4:**

The PM and VOC BACT limits in Section D.9 for the Auxiliary Boiler are only determined by vendor guarantee on lb/MMBtu emission rates. There does not appear to be any performance test or parametric monitoring to verify these BACT limits. The permit must include a method to determine compliance with the BACT limits.

**IDEM Response 4:**

IDEM agrees and is modifying the section to include an initial performance test as follows:

D.9.9 Testing Requirements [326 IAC 2-1.1-11][326 IAC 2-2][326 IAC 2-7-6(1)]

(~~d~~**b**) Within sixty (60) days after achieving the maximum production rate at which the ~~affected facility~~ **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.

**EPA Comment 5:**

Conditions D.11.1 and D.11.2 establish BACT for the coal storage pile and the slag storage pile and handling operation. The permit's BACT includes use of wet suppression techniques that shall be used on an "as-needed basis," but this term is not defined. U.S. EPA recommends the addition of specific conditions that would bring about employment of dust suppression methods.

**IDEM Response 5:**

The term "as-needed" is a common adverb phrase meaning 'according to need' or 'as required'. In the context of the BACT requirements for the coal storage pile and the slag storage pile and handling operation, wet suppression techniques shall be applied on an as-needed basis, such as when dust is generated during operation and weather conditions do not inhibit dust migration. For example, wet suppression techniques would not be necessary if precipitation is present and is sufficiently preventing dust generation and migration.

According to the Fugitive Dust Control Plan included as Attachment A to the modified Part 70 Operating Permit, watering and coal compaction techniques will be used to minimize fugitive dust from the coal storage pile and the slag storage pile and handling operation.

There are no changes to the permit as a result of this comment.

**EPA Comment 6:**

Condition D.11.5 does not state how often opacity readings are to be taken for paved roads/parking areas.

**IDEM Response 6:**

IDEM agrees and will modify Condition D.11.5 as follows:

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.

**EPA Comment 7:**

The results of the NAAQS analysis for $SO_2$ in Table 5 are footnoted to indicate that the maximum impact is a negative number, due to the shutdown of the old boilers. This implies that the old boilers were included in the NAAQS analyses with negative emission rates. It is inappropriate for the NAAQS analysis to model negative emission rates to account for the removal of boilers at Duke Energy Edwardsport Generating Station. Instead, the shutdown sources should be treated as having zero $SO_2$ emissions in the NAAQS analysis. It appears to be appropriate, however, that the Duke Energy Edwardsport Generating Station's PSD increment analysis includes negative emission rates for the sources that are being shut down as part of the facility modification. The modeled emissions should represent the decrease in actual emissions due to the modification, which may not be equal to the former allowable emissions for those sources.

**IDEM Response 7:**

Removing the negative impact of the old boilers from the NAAQS analysis would make the maximum concentration of the annual $SO_2$ projected as a result of emissions from the proposed Edwardsport IGCC plant 4.78 μg/m3. When this projected increase is added to the background of $SO_2$ of 19.4 μg/m3, the total $SO_2$ concentration is calculated to be 24.2 μg/m3. This is still below the NAAQS standard of 80 μg/m3. Negative impacts were only estimated fro the old boilers for the annual averaging periods. Any negative impacts for the PM10 and NOX annual averages did not affect the NAAQS. All short-term averaging periods did not have any negative concentrations.

**Comments from Duke Energy Indiana**

OAQ received comments from Duke Energy Indiana. 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:

**Duke Comment 1:**

The header of the permit documents incorrectly states the original Part 70 permit number with the designation of "SSM".

**IDEM Response 1:**

The header of the permit has been corrected as follows:

Duke Energy Indiana – Edwardsport Generating Station Page 17 of 59
Edwardsport, Indiana Significant Source Modification No. 083-23529-00003 ~~SSM~~ **T** 083-7243-00003
Permit Reviewer: Patrick B. Burton Modified by: Kimberly Cottrell

**Duke Comment 2:**

The source status regarding Section 112 of the Clean Air Act stated in Condition A.1 should be modified to reflect that the facility will not be a major source for the IGCC Plant.

**IDEM Response 2:**

The source status stated in Condition A.1 is modified as follows:

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

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

**Duke Comment 3:**

Throughout the permit and supporting documentation, the terminology referencing the emission units at the existing plant to be retired should be stated as "Emission Units for Existing Coal-Fired Power Plant, To Be Retired Prior to Operation of the IGCC Plant".

**IDEM Response 3:**

IDEM has updated the references to the emission units at the existing plant to be retired throughout the permit as follows:

**~~Operations for Original Coal-Fired Power Plant, To Be Retired~~ Emission Units at the Existing Coal-Fired Power Plant to be Retired prior to operation of the IGCC Plant**

**Duke Comment 4:**

Throughout the permit and supporting documentation, the terminology referencing IGCC should be stated as Integrated Gasification Combined Cycle (IGCC) Electric Generating Plant. The "and" that appears between 'Gasification' and 'Combined' is incorrect and should be deleted.

**IDEM Response 4:**

IDEM has corrected the terminology throughout the permit.

**Duke Comment 5:**

The emission unit descriptions for the gasification block (Condition A.2, paragraphs (B)(a) (1) and (3)) should be updated as follows:

(1) Two (2) refractory-lined, oxygen-blown, entrained flow gasifiers designated as GASIF1 & GASIF2, permitted in 2008~~. The gasifiers are not defined as emission units. However, the~~ **, and two** gasification preheaters designated as GPREHEAT1 and GPREHEAT2, will exhaust through Vent S-5a1 and S-5a2 during startup only.

(2) One (1) natural gas fired thermal oxidizer designated as THRMOX, permitted in 2008, with a maximum pilot rating of 3.85 MMBtu/hr, exhausting to Stack S-4, which will be used ~~as a control device~~ to 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.

(3) One natural gas fired 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, which will be used to combust syngas streams from various operations associated with the gasification process during startup, shutdown and trip events. **An additional heat input of 1.44 MMBtu/hr (natural gas) will be provided to the flare as sweep enrichment gas/flare purge gas.**

**IDEM Response 5:**

IDEM has revised the emission unit descriptions for the gasification block (Condition A.2(B)(a)) as follows:

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

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**(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~~. The gasifiers are not defined as emission units. However, the gasification preheaters designated as GPREHEAT1 and GPREHEAT2 will exhaust~~**, exhausting** through Vent**s** 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.**

~~(2)~~ **(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.**

~~(3)~~ **(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.**

~~(4) Two (2) natural gas fired gasification pre-heaters 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 Vent S-5a1 and S-5a2, respectively.~~

**Duke Comment 6:**

The heat input values stated in Table 1 (Condition A.2, paragraphs (B)(b)(1)) are incorrect. The correct values are 2106 MMBtu/hr for syngas only and 2109 MMBtu/hr for natural gas only. The emission unit description for paragraph (B)(b)(1) of Condition A.2 (power block) should be updated as follows:

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

| ~~Table 1:~~ **Nominal Heat Input Capacity (HHV) for each Combustion Turbine Train** | |
|---|---|
| **Fuel** | **MMBtu/hr** |
| Syngas Only | ~~2098~~ **2106** |
| Natural Gas Only | ~~2094~~ **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.

**IDEM Response 6:**

IDEM has revised the emission unit descriptions for the power block (Condition A.2, paragraphs (B)(b)(1)) as follows:

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

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

(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 nitrogen diluent injection when firing syngas, steam injection to control $NO_X$ when firing natural gas, and nitrogen diluent injection and steam injection when co-firing 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.**

| ~~Table 1:~~ **Nominal Heat Input Capacity (HHV) for each Combustion Turbine Train** | |
|---|---|
| **Fuel** | **MMBtu/hr** |
| Syngas Only | ~~2098~~ **2106** |
| Natural Gas Only | ~~2094~~ **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.

**Duke Comment 7:**

Conditions B.14, D.1.4, D.2.5, D.3.5, and D.4.5 should refer to the Part 70 permit rather than "this permit".

**IDEM Response 7:**

The affected permit conditions have been revised as follows:

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

The Permittee's right to operate this source terminates with the expiration of ~~this permit~~ **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).

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

~~Within the three (3) years following the issuance of this permit, compliance~~ **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.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, ~~or within 180 days after issuance of this permit, whichever is later,~~ 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.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~~, or within 180 days after issuance of this permit, whichever is later~~, 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.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~~, or within 180 days after issuance of this permit, whichever is later~~, 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.

**Duke Comment 8:**

The first paragraph of Condition C.24 should be modified to clarify that all emission units at the existing coal-fired plant shall terminate operations prior to startup of the new IGCC plant.

**IDEM Response 8:**

The first paragraph of Condition C.24 is revised as follows:

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

Pursuant to 326 IAC 2-2, the Permittee shall permanently discontinue ~~the~~ **or terminate** operation of ~~the following operations~~ **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:

**Duke Comment 9:**

In a letter dated November 2, 2005 and written to Title V and FESOP sources, IDEM stated their intention to make changes to permit conditions that are routinely appealed in Title V and FESOP Permits. IDEM further stated that these changes would be incorporated into a pending renewal or when the appeal is resolved. It appears that IDEM has incorporated some of these changes in various conditions within the IGCC source and permit modifications.

Duke Energy Indiana respectfully request that IDEM do as they previously have stated regarding these appealed conditions. This IGCC modification is not a renewal nor intended to be a Title V appeal settlement. DEI asks that IDEM add the conditions that were removed and put the original conditions back in the permit that have been revised throughout the permit. Alternatively, DEI requests that IDEM provide assurance that the issuance of SSM No. 083-23529-00003 and SPM No. 083-23531-00003 with revisions to or deletions of certain permit conditions of the current Title V permit to which DEI has objections in its administrative appeal of Title V Operating Permit No. T 083-7243-00003, docketed before the OEA as Cause No. 04-A-J-3436, will not adversely affect the rights of DEI to pursue its appeal of these permit conditions in the pending administrative proceeding or DEI's rights under the administrative stay of certain of these permit conditions as now in effect.

**IDEM Response 9:**

IDEM is currently evaluating prospective changes to the permit conditions of Title V Permit No. T 083-7243-00003 that are the subject of the pending administrative permit appeal proceeding and which are proposed to be revised in draft SSM No. 083-23529-00003 and SPM No. 083-23531-00003. Notwithstanding the proposed revisions, IDEM intends that any resolution of the pending appeal of these conditions will be addressed in that proceeding and the issuance of SSM No. 083-23529-00003 and SPM No. 083-23531-00003 will not affect the pending appeal proceeding or the administrative stay of certain of these permit conditions during the pendency of the appeal. Therefore, no change has been made to draft SSM No. 083-23529-00003 and SPM No. 083-23531-00003 as a result of this comment.

**Duke Comment 10:**

Duke Energy Indiana's administrative appeal of Title V Operating Permit No. T 083-7243-00003, docketed before the OEA as Cause No. 04-A-J-3436, also raises challenges to certain conditions of the permit which (i) pertain to the existing emission units at Edwardsport Generating Station and (ii) are not proposed for revision in SSM No. 083-23529-00003 and SPM No. 083-23531-00003. DEI requests assurance that the prospective issuance of SSM No. 083-23529-00003 and SPM No. 083-23531-00003 will not affect the pending appeal proceeding, the rights of appeal preserved by DEI in that proceeding, or the stay of certain of the contested permit provisions as currently in effect in the appeal proceeding.

**IDEM Response 10:**

IDEM is currently evaluating prospective changes to the permit conditions of Title V Permit No. T 083-7243-00003 that are the subject of the pending administrative permit appeal proceeding and which are not proposed to be revised in draft SSM No. 083-23529-00003 and SPM No. 083-23531-00003. Any resolution of the pending appeal of these conditions will be addressed in that proceeding and the issuance of SSM No. 083-23529-00003 and SPM No. 083-23531-00003 is not intended to affect the pending appeal proceeding or the administrative stay of certain of these permit conditions during the pendency of the appeal. Therefore, no change has been made to draft SSM No. 083-23529-00003 and SPM No. 083-23531-00003 as a result of this comment.

**Duke Comment 11:**

Condition D.1.8(b) incorrectly references Condition D.1.9 instead of D.1.7.

**IDEM Response 11:**

The condition reference in Condition D.1.8 is revised as follows:

D.1.8 Record Keeping Requirements

(b) To document compliance with Condition ~~D.1.9~~ **D.1.7**, the Permittee shall maintain records of visible emission notations of the boiler stack exhaust.

**Duke Comment 12:**

The numbering in Conditions D.2.13(b), D.3.13(b), and D.4.13(b) is confusing.

**IDEM Response 12:**

IDEM has revised Conditions D.2.13(b), D.3.13(b), and D.4.13(b) as follows:

D.2.13 Record Keeping Requirements

(b) To document compliance with Condition~~s~~ 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~~s~~ 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**~~a~~) through (**E**~~e~~) below. Records maintained for (**A**~~a~~) through (**E**~~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**~~1~~) Calendar dates covered in the compliance determination period; and;

(**B**~~2~~) Actual coal usage since last compliance determination period; and;

(**C**~~3~~) Sulfur content, heat content, and ash content; and;

(**D**~~4~~) Sulfur dioxide emission rates; and;

(**E**~~5~~) Vendor analysis of coal and coal supplier certification.

D.3.13 Record Keeping Requirements

(b) To document compliance with Condition~~s~~ 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~~s~~ 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.

(~~2~~**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**~~a~~) through (**E**~~e~~) below. Records maintained for (**A**~~a~~) through (**E**~~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**~~1~~) Calendar dates covered in the compliance determination period; and;

(**B**~~2~~) Actual coal usage since last compliance determination period; and;

(**C**~~3~~) Sulfur content, heat content, and ash content; and;

(**D**4) Sulfur dioxide emission rates; and;

(**E**~~5~~) Vendor analysis of coal and coal supplier certification.

D.4.13 Record Keeping Requirements

(b) To document compliance with Conditions~~s~~ D.4.3, 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.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**~~a~~) through (**E**~~e~~) below. Records maintained for (**A**~~a~~) through (**E**~~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**~~1~~) Calendar dates covered in the compliance determination period; and;

(**B**~~2~~) Actual coal usage since last compliance determination period; and;

(**C**~~3~~) Sulfur content, heat content, and ash content; and;

(**D**~~4~~) Sulfur dioxide emission rates; and;

(**E**~~5~~) Vendor analysis of coal and coal supplier certification.

**Duke Comment 13:**

Paragraph (e)(1) of Condition D.8.12 should be updated to specify that CFM is an abbreviation for cubic feet per minute.

**IDEM Response 13:**

IDEM has revised paragraph (e)(1) of Condition D.8.12 as follows:

D.8.12 Record Keeping Requirements

(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.

**Duke Comment 14:**

In Condition D.9.2, the particulate matter limit for the cooling tower should be 3.2 lb/hr, and the total dissolved solids limit should be specified as "in the recirculating cooling water".

**IDEM Response 14:**

The new limit for the cooling tower is more stringent than the 6.4 lb/hr that was proposed as BACT. IDEM has revised paragraphs (a) and (b) of Condition D.9.2 as follows:

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

(a) Particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions shall not exceed ~~6.4~~ **3.2** lbs/hr.

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

**Duke Comment 15:**

In Condition D.9.4(b), the particulate matter limit for the turbine gas conditioning preheaters should be 0.0075 lbs/MMBtu.

**IDEM Response 15:**

IDEM has revised Condition D.9.4(b) as follows:

D.9.4 Turbine Gas Conditioning Preheater PSD BACT Limit [326 IAC 2-2]

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

**Duke Comment 16:**

The testing requirements in Condition D.9.9 should be clarified to specify that testing of one combustion train can demonstrate compliance.

**IDEM Response 16:**

IDEM has revised the testing requirements in Condition D.9.9 as follows:

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 ~~the affected facility~~ **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 $PM_{2.5}$). ~~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.~~

~~This period 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 when firing natural gas.~~

(~~b~~**2**) **Syngas Only:**
Within sixty (60) days after achieving the maximum production rate at which ~~the affected facility~~ **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. ~~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.~~

~~This period 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 when firing syngas.~~

(~~c~~**3**) **Co-firing Syngas and Natural Gas:**
Within sixty (60) days after achieving the maximum production rate at which ~~the affected facility~~ **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 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.~~

~~This period 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 when co-firing syngas and natural gas.~~

**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.)**

(~~d~~**b**) Within sixty (60) days after achieving the maximum production rate at which the ~~affected facility~~ **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.**

**Duke Comment 17:**

The record keeping requirement in original Condition D.9.14(b)(1) should be clarified to specify that record of the total dissolved solids (TSD) of the coolant water **and gallons of coolant water pumped through the cooling tower** should be maintained on a monthly basis.

**IDEM Response 17:**

IDEM has revised the record keeping requirement in original Condition D.9.14(b)(1) (now Condition D.9.13) as follows:

~~D.9.14~~ **D.9.13** Record Keeping Requirements

(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.

**Duke Comment 18:**

The requirement in paragraph (b) of 40 CFR 60.48Da is applicable to the facility and should be added to the permit.

**§ 60.48Da Compliance provisions.**

(b) ~~Intentionally omitted~~ **Compliance with the NOx emission limitation under §60.44Da(a)(1) constitutes compliance with the percent reduction requirements under §60.44Da(a)(2).**

**IDEM Response 18:**

IDEM has added the applicable portions of 40 CFR 60.48Da (b) to the permit.

**Comments from Duke Energy Indiana on the Technical Support Document**

IDEM does not amend the Technical Support Document (TSD) because the technical support material is maintained to document the original review that was placed on public notice. This addendum to the TSD documents all comments, responses to comments and changes made from the time the permit was drafted until a final decision is made.

**TSD Comment 1:**

Paragraph (c) of the Source Status section and paragraph (c) of the Source Status Determination section of the TSD should be modified as follows:

**<u>Source Status section</u>**

(c) 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 **existing** source is a major source under Section 112 of the Clean Air Act (CAA). **However, after the existing emission units are permanently retired and the IGCC Plant subsequently begins operations, the source will be a minor source under Section 112 of the Clean Air Act.**

**<u>Source Status Determination section</u>**

(c) Part 70 Source
Duke Energy Indiana – Edwardsport Generating Station is a Part 70 **source** because one or more attainment regulated pollutants are emitted at a rate of 100 tons per year. **Edwardsport Generating Station will no longer be a major HAP source after retirement of the existing units and prior to commencement of operation of the IGCC units.**

**IDEM Response 1:**

This addendum serves to clarify the explanation of the Source Status before and after installation of the IGCC project. IDEM has already updated Condition A.1 of the permit to address these changes.

**TSD Comment 2:**

The emission unit descriptions in the Proposed New Emission Units section of the TSD should be updated to match the revisions made in the permit.

**IDEM Response 2:**

IDEM has already updated Condition A.2 and the facility description boxes in Sections D, E, F, and G of the permit to address these changes.

**TSD Comment 3:**

The PTE listed for CO and mercury in Table 6, IGCC Plant - PTE Before Controls of the Modification, in the Permit Level Determination – Part 70 section of the TSD should be 917.6 and 0.036 tons per year, respectively.

**IDEM Response 3:**

This addendum serves to clarify the explanation of the Part 70 Permit Level Determination for IGCC project. IDEM compared the data in Table 6 to the emission calculations in Appendix A of the Technical Support Document. The correct values for each item are listed below:

- PTE: CO = 917.6 tpy

- PTE: mercury = 0.036 tpy

**TSD Comment 4:**

The Permit Level Determination – PSD or Emission Offset section of the TSD should be modified as follows:

Tables 8 and 9 below summarize 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 Source Modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit. Table 8 presents the net change in emissions associated with the IGCC project based on continuous operation with syngas**/natural gas** combustion in the CTs (referred to as the "normal operating mode") without periods of startup or shutdown. Table 9 presents the net change in emissions from the IGCC project taking into account ~~normal operations, again with syngas combustion in the CTs, and~~ startup/shutdown periods**, as well as trip events** (referred to as the "normal/startup/shutdown/trip operating mode). Tables 8 and 9 represent opposite extremes of operational mode for the IGCC facility, ranging from continuous normal mode operation with no start-up events in an annual period (Table 8) to the maximum number of start-ups**/shutdowns** (76 annual events) projected by Duke Energy with normal mode operating hours correspondingly reduced (Table 9). Any other intermediate scenario involving a number of start-ups between 0 and 76 will result in potential to emit values for each pollutant at a commensurate level between the values depicted on Tables 8 and 9. The net change in emissions from Tables 8 and 9 were used in determining initial PSD applicability. From these Tables, it can be concluded that a significant increase in net emissions is projected from the IGCC project for CO, $PM/PM_{10}/PM_{2.5}$, and VOC.

**<u>Changes Regarding Table 8:</u>**

- The emission unit listing for the turbines in Table 8 should be stated as Two Combustion Turbines on Syngas **or Syngas/Natural Gas**.
- The potential to emit (PTE) listed for fugitive $PM_{10}/PM_{2.5}$ should be 10.1 tons per year (tpy) instead of 11.52 tpy.
- The contemporaneous decrease listed for CO should be 69.1 tpy instead of 69.5 tpy.
- The contemporaneous decrease listed for PM should be 207.3 tpy instead of 207.4 tpy.
- The total for modification after netting listed for CO should be 848.4 tpy instead of 848.0 tpy.
- The total for modification after netting listed for PM should be 209.9 tpy instead of 209.6 tpy.

**<u>Changes Regarding Table 9:</u>**

- The PTE listed for fugitive $PM_{10}/PM_{2.5}$ should be 10.05 tpy instead of 11.52 tpy.
- The total for modification listed for $PM_{10}/PM_{2.5}$ should be 74.88 tpy instead of 81.0 tpy.
- The contemporaneous decrease listed for CO should be 69.1 tpy instead of 69.5 tpy.
- The total for modification after netting listed for CO should be 392.5 tpy instead of 392.1 tpy.
- The total for modification after netting listed for $NO_X$ should be -1986.5 tpy instead of -1987.0 tpy.

- The total for modification after netting listed for $PM_{10}/PM_{2.5}$ should be 27.183 tpy instead of 33.3 tpy.

- The total for modification after netting listed for $SO_2$ should be 10,175.9 tpy instead of 10,166.9 tpy.

**IDEM Response 4:**

This addendum serves to clarify the explanation of the PSD Permit Level Determination for IGCC project. IDEM compared the data in Tables 8 and 9 to the emission calculations in Appendix A of the Technical Support Document. The correct values for each item are listed below:

**Corrections to Table 8:**

- PTE: fugitive $PM_{10}$ = 10.05 tpy
- PTE: fugitive $PM_{2.5}$ = 1.51 tpy
- contemporaneous decrease: CO = 69.1 tpy
- contemporaneous decrease: PM = 207.3 tpy
- contemporaneous decrease: $PM_{10}/PM_{2.5}$ = 47.7 tpy
- total for modification after netting: CO = 848.4 tpy
- total for modification after netting: PM = 209.9 tpy
- total for modification after netting: $PM_{10}$ = 349.4 tpy
- total for modification after netting: $PM_{2.5}$ = 340.8 tpy

**Corrections to Table 9:**

- PTE: fugitive $PM_{10}$ = 10.05 tpy
- PTE: fugitive $PM_{2.5}$ = 1.51 tpy
- total for modification: $PM_{10}$ = 74.87 tpy
- total for modification: $PM_{2.5}$ = 66.31 tpy
- contemporaneous decrease: CO = 69.1 tpy
- total for modification after netting: CO = 392.5 tpy
- total for modification after netting: $NO_X$ = -1986.45 tpy
- total for modification after netting: $PM_{10}$ = 27.15 tpy
- total for modification after netting: $PM_{2.5}$ = 18.59 tpy
- total for modification after netting: $SO_2$ = -10,175.87 tpy

**TSD Comment 5:**

The explanation of the Compliance Assurance Monitoring (CAM) requirements in paragraph (c) of the Federal Rule Applicability Determination section of the TSD should be modified as follows:

> The requirements of 40 CFR Part 64, CAM, are not applicable to the following processes/emission units because ~~proposed modification will not add any additional~~ **no** control devices **will be incorporated** for these processes/emission units:

**IDEM Response 5:**

There are no changes to the permit or the applicability of CAM requirements as a result of this clarification.

**TSD Comment 6:**

Table 13, Summary of Compliance Testing Requirements, of the TSD should be modified as follows:

**Changes Regarding Table 13:**

- Clarify that the testing for the combustion turbines is for each fuel option.
- Clarify that the $SO_2$, $NO_X$, Hg, and PM limits for the combustion turbines are from the NSPS.
- Add the following pollutant limits for the combustion turbines: 0.019 lbs PM/MMBtu, 0.046 lbs CO/MMBtu, and 0.002 lbs VOC/MMBtu.
- Clarify that the Flare Pilot is an elevated open flare.
- Delete the VOC testing requirements for the Flare Pilot because there is currently no feasible method of VOC emission monitoring for this device.
- The $SO_2$ limit for the thermal oxidizer should be a lb/hr limit. This limit is not based on the gasification input, and there is a limit for normal operation as well as startup and shutdown.
- Add the limit for CO from the auxiliary boiler of 0.036 lbs/MMBtu with a testing frequency of once every 5 years.

**IDEM Response 6:**

IDEM compared the data in Table 13 to the permit requirements. The corrected information for each item is listed below:

**Corrections to Table 13:**

- The testing requirements for the combustion turbines (Condition D.9.9) are for each fuel option.
- $SO_2$ and $NO_X$ limits for the combustion turbines are included in Condition D.7.1 as part of the plant-wide $SO_2$ and $NO_X$ limits for the IGCC plant. PM limits for the combustion turbines are included in Condition D.9.1. NSPS limits for Stationary Compression Ignition Internal Combustion Engines are included in Conditions G.4.2 [40 CFR Part 60, Subpart OOO], G.5.2 [40 CFR Part 60, Subpart HHHH], and G.6.2 [40 CFR Part 60, Subpart IIII].

- The CO, PM, and VOC limits (Condition D.9.1) for the combustion turbines are:

  *CO (syngas only / co-firing syngas and natural gas)*: 0.046 lbs/MMBtu

  *CO (natural gas only)*: 0.042 lbs/MMBtu

  *PM (syngas only / co-firing syngas and natural gas)*: 0.019 lbs/MMBtu

  *PM (natural gas only)*: 0.009 lbs/MMBtu

  *VOC (syngas only / co-firing syngas and natural gas / natural gas only)*: 0.002 lbs/MMBtu

- The emission unit descriptions for the flare have been modified to clarify that the Flare Pilot is an elevated open flare. Refer to IDEM's response to Duke Comment 5 (pages 18-19) for the revised emission unit description.

- There are no VOC testing requirements included in the permit for the Flare Pilot.

- The $SO_2$ limits for the thermal oxidizer are stated in the permit in pounds per hour (Condition D.7.2). These limits do not reference gasification input.

- The CO emission limit for the auxiliary boiler is 0.036 lbs/MMBtu (Condition D.9.3). The testing frequency for this CO emission limit is once every 5 years (Condition D.9.9).

**TSD Comment 7:**

Table 14, IGCC Plant Monitoring Applicability, of the TSD should be modified as follows:

**Changes Regarding Table 14:**
- The PM limit for the combustion turbines should state that the limit is based on gross output.

**IDEM Response 7:**

The monitoring requirement listed in Table 14 specifies that the CEM data is based on a gross output limit. Condition D.9.1, does not specify that the particulate BACT limit is based on gross output. There is no CEMS requirement included in Condition D.9.11 for PM. The applicable portions of Conditions D.9.1 and D.9.11 are shown below for comparison purposes. *There are no changes to the permit as a result of this comment*.

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:

(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.

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.

## Public Comments - Technical

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:

**Technical Comment 1:**

The PSD Increment Inventory was deficient. There are a number of major sources that will potentially add to the air pollution impacts from the proposed plant. Many of these have undergone at least one major modification since the major source baseline date. These plants must be included in the modeling inventory as a consuming increment.

**IDEM Response 1:**

IDEM updates the PSD increment inventory whenever a PSD air quality analysis project is assigned. All information is imported into the current inventory. At the receptor of maximum concentration for any PSD pollutant, no other source contributed significantly to the concentration.

**Technical Comment 2:**

Modeling must be redone based on the worst case emissions. For both NAAQS and PSD increment compliance demonstrations, the emission rate for the proposed new source or modification must reflect the maximum allowable operating conditions as expressed by the federally enforceable emission limit, operating level, and operating factor for each applicable pollutant and averaging time. An annual or 30 day limit is not representative of "worst case emissions" during a shorter period of time.

- For $SO_2$ and $NO_X$, the proposed plant is only subject to annual "synthetic minor" limits.
- For PM, there are no enforceable hourly emission limits on the material handling, coal storage, slag storage, and roadways.

**IDEM Response 2:**

Short term emission limits were used for modeling purposes. The modeled emission rates for Duke Energy's IGCC project were greater than the permitted limits. Modeling was completed using initial calculations. The permitted limits are the final calculations. This table shows the modeled rates versus the permitted limits.

| Comparison of Modeled Emission Rates to Permit Limits | | | |
|---|---|---|---|
| **Pollutant** | **Modeled Emission Rate** (tpy) | **Permitted Emission Limit** (tpy) | **Difference** (tpy) |
| VOC | 87.6 | 36.8 | -50.8 |
| $PM_{10}$ | 446.82 | 397.1 | -49.72 |
| $NO_x$ | 2416.49 | 2121.5 | -294.99 |
| $SO_2$ | 465.3 | 358.5 | -106.8 |
| CO | 1284.04 | 917.05 | -366.99 |
| Pb | 0.037 | 0.037 | 0 |
| Fluorides | 0.0 | 0.0 | 0 |
| Sulfuric Acid Mist | 56.1 | 56.1 | 0 |

In each case the modeled rates were above the permitted limits and all standards were met.

- Short term emission limits are included for $SO_2$ and $NO_X$ in Condition D.7.5 for periods of startup and shutdown. (See IDEM Response to EPA Comment 2, pages 2-14.)

- Hourly emission limits are not practical from material handling, coal storage, slag storage, and roadways.

**Technical Comment 3:**

The permit must ensure that the assumptions made for modeling are enforceable. Emissions were modeled from material handling operations as if the emissions would be generated at a constant rate; however, material handling operations (coal unloading and storage pile maintenance) occur over a short period of time with high hourly emission rates during those times. The modeling appears to assume a "controlled" emission rate from coal unloading, roads, and storage piles based on the application of water and other activities assuming high levels of control (50% paved roads, 95% unpaved roads, 50% wind erosion); however, no testing or monitoring is required to verify the level of control.

**IDEM Response 3:**

Modeled emissions rates were greater than the permitted limits. Emission rate calculations are based on the current approved methodology in U.S. EPA's AP-42 Compilation of Air Emission Factors. In this case, BACT was not determined to be a specified level of control based on percentages. Control methods for material handling are variable; therefore, Duke Energy is required to implement and maintain a Fugitive Dust Control Plan.

**Technical Comment 4:**

Ozone impacts must be determined based on a VOC threshold of 100 tons per year.

**IDEM Response 4:**

An air quality analysis is not performed for VOCs/Ozone 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 that can take into account small spatial scales or single source PSD modeling for ozone.

**Technical Comment 5:**

Greater analysis of CO impacts on soil and vegetation downwind should be required.

**IDEM Response 5:**

All PSD applicants must prepare an additional impact analysis for each criteria pollutant. The analysis assesses the impacts of air pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review and from associated growth. The additional impact analysis generally has three parts: growth; soil and vegetation; and visibility impairment. The soil and vegetation analysis should be based on an inventory of the soil and vegetation types found in the impact area. This inventory should include all vegetation with any commercial or recreational value. The secondary NAAQS will be the significance levels used for the endangered species.

IDEM followed U.S. EPA guidance when performing the additional impacts analysis. The NAAQS are intended to provide protection of human health and welfare. In this regard, the secondary NAAQS provide protection for various animal species, soils and plant life. The dispersion modeling analyses demonstrate compliance with the NAAQS; therefore, no adverse impacts to soils, vegetation and endangered species are anticipated to occur due to operation of the proposed Edwardsport IGCC Generating Station. It is noted in the 1990 Draft New Source Review Workshop Manual that soybeans may be potentially sensitive to $SO_2$. In this regard, predicted 24-hour $SO_2$ concentrations that are reflective of worst case emissions from the proposed Duke Energy plant are considerably below the level at which significant $SO_2$ impacts on soybeans have been demonstrated (greater than 260 $\mu g/m_3$ on a 24-hour period basis).

**Technical Comment 6:**

More recent and more proximal meteorological data should have been used.

**IDEM Response 6:**

Meteorological data from 1988-1992 from Evansville, Indiana, surface air station and mixing heights from Peoria, Illinois, was used for the modeling analysis. The more proximal National Weather Service Stations, Lawrenceville and Huntingburg do not collect enough data to be processed for use with AERMET and can not be used in AERMOD. The meteorological data is the most recent data that has been processed. It is believed that in a five year period any meteorological event may occur and, further, that the meteorological data employed in the air quality analysis for the Duke Energy permits are adequately representative.

**Technical Comment 7:**

The permit should include preconstruction and post construction monitoring requirements for $PM_{2.5}$, ozone ($O_3$), and CO.

**IDEM Response 7:**

All monitoring required by under the Part 70 and PSD rules have been incorporated into the modified operating permit. IDEM does not believe any additional ambient monitoring is necessary beyond the existing air monitoring network.

**Technical Comment 8:**

IDEM monitor site locations are identified by a nine-digit number with no other description of the monitor site. Comparison of these numbers to the September 19, 2007, Indiana Ambient Air Monitoring Annual Network Plan revealed that not a single one of the referenced sites could be found in the September plan.

**IDEM Response 8:**

The monitors listed in the Air Quality Analysis refer to the monitoring sites that were in existence when the background data was collected in 2005-2007. Some of these monitors are no longer in use. Monitor 18-051-0010 was located in Princeton, Indiana, along CR 550 S, and Monitor 18-163-0015 was located in Evansville, Indiana, at the 425 West Mill Road Fire Station.

IDEM has updated Table 4 of the Air Quality Analysis with the current monitor locations below:

| **Existing Monitoring Data Used For Background Concentrations*** | | | | |
|---|---|---|---|---|
| **Pollutant** | **Monitoring Site** | **Location** | **Averaging Period** | **Concentration** ($\mu g/m^3$) |
| $NO_X$ | ~~18-051-0010~~ **18-163-0012** | **Evansville, 425 West Mill Road** | Annual | ~~17.1~~ **19.4** |
| $PM_{10}$ | 18-037-2001 | **Jasper, 200 W 6th St** | Annual | 26 |
| $PM_{10}$ | 18-037-2001 | **Jasper, 200 W 6th St** | 24 hour | 46.3 |
| CO | ~~18-163-0015~~ **18-163-0019** | **Evansville, Harwood MS** | 1 hour | ~~6297.5~~ **3698.4** |
| CO | ~~18-163-0015~~ **18-163-0019** | **Evansville, Harwood MS** | 8 hour | ~~3893~~ **2255.7** |
| $SO_2$ | 18-027-0002 | **Daviess County, West of SR 57** | 3 hour | ~~210.4~~ **225.3** |
| $SO_2$ | 18-027-0002 | **Daviess County, West of SR 57** | 24 hour | ~~86.5~~ **76** |
| $SO_2$ | 18-027-0002 | **Daviess County, West of SR 57** | 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.

The changes above result in the following updates to Table 5 of the Air Quality Analysis:

| **NAAQS Analysis**[3] | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Pollutant** | **Year** | **Time-Averaging Period** | **Maximum Concentration** ($\mu g/m^3$) | **Background Concentration** ($\mu g/m^3$) | **Total** ($\mu g/m^3$) | **NAAQS Limit** ($\mu g/m^3$) | **NAAQS Violation** |
| $NO_X$ | 1991 | Annual[1] | 19.9 | ~~17.1~~ **19.4** | ~~37.0~~ **39.3** | 100 | NO |
| $PM_{10}$ | 1992 | Annual[1] | 0.9 | 26 | 26.9 | 50 | NO |

**NAAQS Analysis[3]**

| Pollutant | Year | Time-Averaging Period | Maximum Concentration ($\mu g/m^3$) | Background Concentration ($\mu g/m^3$) | Total ($\mu g/m^3$) | NAAQS Limit ($\mu g/m^3$) | NAAQS Violation |
|---|---|---|---|---|---|---|---|
| $PM_{10}$ | 1988 | 24 hour | 23.7 | 46.3 | 70.0 | 150 | NO |
| CO | 1988 | 1 hour | 8312 | ~~6297.5~~ **3698.4** | ~~14609.5~~ **12010.4** | 40000 | NO |
| CO | 1992 | 8 hour | 3850 | ~~3893~~ **2255.7** | ~~7743~~ **6105.7** | 10000 | NO |
| $SO_2$ | 1991 | 3 Hour[2] | 70.9 | ~~210.4~~ **225.3** | ~~281.3~~ **296.2** | 1300 | NO |
| $SO_2$ | 1988 | 24 hour[2] | 41.0 | ~~86.5~~ **76** | ~~127.5~~ **127** | 365 | NO |
| $SO_2$ | 1991 | Annual[1] | ~~-1.9~~[4] **4.8** | 19.4 | ~~17.5~~ **24.2** | 80 | NO |

[1] First highest values per EPA NSR manual October 1990.
[2] High 2nd high values per EPA NSR manual October 1990.
[3] 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 3 maximum concentrations are from Duke Energy only.
[4] ~~Negative impact due to shutdown of the old boilers.~~

As shown above, the NAAQS would not be violated when the modeling includes the new background concentrations.

**Technical Comment 9:**

IDEM improperly credited emissions decreases in the netting analysis for the IGCC plant. The baseline timeframe is outside the period five years before construction. Noncompliant emissions and emissions exceeding the allowable emissions should be excluded from the baseline. Declining emissions from the existing emission units do not have the same qualitative significance as constant emissions from the new emissions for their 30+ years of life. The emissions reductions from the old boilers are not voluntary because these emission units are at the end of their service life.

**IDEM Response 9:**

The application uses 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.

Regarding the phrase "qualitative significance", the term is found in Indiana's NSR rules at 326 IAC 2-2-1(jj):

> (6) A decrease in actual emissions is creditable only to the extent that:
> . . . (C) it has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change; . . . .

See, 40 CFR 2.21(b)(3)(vi)(c).

Although relatively few guidance documents are available that discuss the import of the phrase "qualitative significance" (also known as the "health and welfare equivalence" provision) for the netting analysis, the extant guidance is clear. In 1989, in response to a settlement agreement, the EPA reconsidered several aspects of its 1980 NSR regulations, including the "qualitative significance" provision. *See*, 54 Fed.Reg. 27286 (June 28, 1989). EPA stated that the implementation of the provision would be limited to circumstances where the permitting authority has "reason to believe that the reduction in ambient concentrations from the emissions decrease will not be sufficient to prevent the proposed emissions increase from causing or contributing to a violation of any NAAQS or PSD increment." The preamble also observed that "many industrial processes are sufficiently similar that they can be considered as having an equivalent impact on health and welfare. Therefore, where netting takes place between the same or similar combustion units, fuels, or processes, equivalency may, in most cases, be assumed." *Id.*
The 1990 Draft New Source Review Workshop Manual echoed this interpretation stating that "current EPA policy is to assume that an emissions decrease will have approximately the same qualitative significance for public health and welfare as that attributed to an increase, unless the reviewing agency has reason to believe that the reduction in ambient concentrations from the emissions decrease will not be sufficient to prevent the proposed emissions increase from causing or contributing to a violation of any PSD or NAAQS increment." (See 1990 Draft NSR Workshop Manual, pp. A38-39.) Thus, the term “qualitative significance” does not have the meaning suggested by the commenters. Lastly, the State’s PSD regulations do not support the position proposed by commenters that an emissions decrease would not be “voluntary” and thus not creditable if an emissions unit being shutdown is approaching the end of its useful life. The creditable nature of an emission decrease has not been construed in the suggested manner.

**Technical Comment 10:**

IDEM failed to conduct a BACT analysis for $PM_{2.5}$ and failed to include a $PM_{2.5}$ BACT limit in the permit.

**IDEM Response 10:**

All references to particulate emissions in the permit and supporting documentation are stated as "PM" and include PM, $PM_{10}$ and $PM_{2.5}$ (filterable PM, filterable and condensable $PM_{10}$). $PM_{10}$ and $PM_{2.5}$ emissions are assumed to be equal to total PM emissions for each of the BACT analyses. For these analyses, IDEM has used the approach approved by the U.S. EPA to use $PM_{10}$ as a surrogate for $PM_{2.5}$.

On April 25, 2007, the U.S. EPA finalized its PM2.5 implementation rule. However, the U.S. EPA decided **not** to include the NSR program in the implementation rule and stated that, "because there was an interim surrogate NSR program in place" (which allowed states to use PM10 as a surrogate between the effective date of the PM2.5 NAAQS designation and until the U.S. EPA promulgates major NSR regulations for the implementation of PM2.5), 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 PM2.5 increments, Significant Impact Levels, and a Significant Monitoring Concentration to facilitate implementation of the PM2.5 PSD program. The preamble to that rule cites the interim surrogate policy for use of PM10 in lieu of PM2.5 as part of a transition program for PM2.5 implementation in NSR. The latter implementation rule has not been finalized.

**Technical Comment 11:**

The draft permit does not include sufficient BACT limits for the combustion turbines. The BACT limits for CO, PM, and VOC are not as low as other proposed IGCC plants.

**IDEM Response 11:**

- **PM**: The Taylorville permit (Section 4.2.2 (b)(i)) limits *filterable* PM emissions to 0.0090 lb/MMBtu (3-hr average) for syngas combustion and 0.007 lb/MMBtu (3-hr average) for natural gas combustion. The Taylorville permit also limits *total* (filterable and condensable) $PM_{10}$ emissions to 0.0220 lb/MMBtu for syngas and 0.0110 lb/MMBtu for natural gas (both limits are for 3-hr average).

  The Edwardsport draft permit limits *total* (filterable and condensable) $PM/PM_{10}/PM_{2.5}$ emissions to 0.0190 lb/MMBtu (3-hr average) for syngas combustion or co-firing of syngas and natural gas, and 0.0090 lb/MMBtu (3-hr average) for natural gas. These limits are more stringent than the Taylorville limits for total (filterable and condensable) $PM_{10}$ emissions.

- **CO**: The Taylorville permit lists CO limits of 0.0490 lb/MMBtu (24-hr average) for syngas combustion and 0.0450 lb/MMBtu (24-hr average) for natural gas.

  The Edwardsport draft permit proposes CO limits of 0.0460 lb/MMBtu (24-hr average) for syngas or co-firing of syngas and natural gas, and 0.042 lb/MMBtu (24-hr average) for natural gas. These limits are more stringent than those found in the Taylorville permit.

- **VOC**: The Taylorville permit limits VOC emissions to 0.0015 lb/MMBtu (3-hr average) for combustion of syngas and 0.0017 lb/MMBtu (24-hr average) for natural gas.

  The Edwardsport draft permit proposes a VOC emission limit of 0.002 lb/MMBtu (3-hr average) for the turbine/HRSG process for combustion of syngas, natural gas, or any combination thereof. These limits are essentially equivalent in practical terms to those of the Taylorville permit

**Technical Comment 12:**

The draft permit does not include adequate BACT limits for the auxiliary boiler. The BACT limits for $PM_{10}$ and VOC are not as low as other proposed natural gas fired boilers.

**IDEM Response 12:**

- **$PM_{10}$**: Three facilities have lower BACT limits for $PM_{10}$: Mirant Mid-Atlantic, LLC, has a 60 MMBtu/hr boiler that is limited to 0.004 lbs/MMBtu; Longview Power, LLC, has a 225 MMBtu/hr boiler that is limited to 0.0022 lbs/MMBtu; and Columbia Energy Center, has a 350 MMBtu/hr boiler that is limited to 0.005 lbs/MMBtu.

  The Edwardsport draft permit limits *total* (filterable and condensable) $PM/PM_{10}/PM_{2.5}$ emissions to 0.0075 lb/MMBtu for the auxiliary boiler and limits the maximum heat input to 300 MMBtu/hr.

The PM limits for other auxiliary boilers were based on good combustion practices and the use of natural gas. The limits proposed by Duke Energy were based on AP-42 and are equivalent to the BACT limitations established for similar boilers rated at 300 MMBtu/hr. Data to determine how the lower limits were calculated for the other facilities was not readily available. There are no add-on control technologies that can be used on a natural gas fired boiler to control PM emissions.

- **VOC**: Three facilities have slightly lower BACT limit for VOC of 0.004 lbs/MMBtu. Two of these boilers have a heat input capacity of 247 MMBtu/hr and the 3rd capacity was not available.

  The Edwardsport draft permit proposes a VOC emission limit of 0.005 lb/MMBtu for the auxiliary boiler and limits the maximum heat input to 300 MMBtu/hr. The VOC BACT limit is equivalent to the limit established by the three other facilities.

**Technical Comment 13:**

The draft permit does not include adequate BACT limits for the emergency generator. BACT should include a numeric limit based on using clean fuels and a case-by-case analysis rather than using the value from the New Source Performance Standard.

**IDEM Response 13:**

- **PM**: The most effective method for control of particulate emissions resulting from operation of the emergency generator at an IGCC plant is the implementation of good combustion practices, use of low sulfur fuel oil or diesel fuel and limited hours of operation.

- **CO**: The most effective method for control of CO emissions resulting from operation of the emergency generator at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent to the design of the individual combustion devices.

- **VOC**: The most effective method for control of VOC emissions resulting from operation of the emergency generator at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent to the design of the individual combustion devices.

No BACT limits have been established for emergency equipment at existing IGCC plants; therefore, the New Source Performance Standards (NSPS) in 40 CFR Part 60, Subpart IIII, were used to establish BACT. Refer to *Technical Comment* and *IDEM Response 15* below for additional explanation about the choice of low sulfur diesel fuel as BACT.

**Technical Comment 14:**

The BACT analysis and BACT limit for PM emissions from the cooling towers are incomplete. The permit should include a PM limit rather than a drift rate requirement.

**IDEM Response 14:**

The permit requires the installation of a high efficiency drift eliminator with a drift flow rate of less than 0.0005 percent, to be utilized at all times the cooling tower is in operation (Condition D.9.2(c)). This BACT determination is consistent with those for other similar steam electric generating facilities. The permit also limits total dissolved solids content of the recirculating cooling water to 5,000 parts per million (Condition D.9.2(b)) and limits $PM/PM_{10}/PM_{2.5}$ emissions to 3.2 lbs/hr (Condition D.9.2(a), as amended above in *Duke Comment* and *IDEM Response 14* on page 26).

**Technical Comment 15:**

Use of Air Cooled Condensers (ACC) as an alternative to cooling towers should be considered in the cooling tower BACT analysis

Natural Gas is a cleaner fuel than coal-syngas and must be used to establish BACT limits for the combustion turbines. Requiring the use of natural gas rather than syngas would not "redefine" the source because the source would still be producing the same end product – electricity.

BACT for the emergency generator should be based on using clean fuels, specifically natural gas.

**IDEM Response 15:**

The BACT requirements of the Clean Air Act (CAA) do not dictate process equipment selections by the owner or operator of a proposed source. Rather, BACT governs the determination of air emission controls to be applied to the process equipment and operations identified by the owner/operator for the new or modified source.

All three proposed BACT requirements set out in the above comment would have the effect of redefining the Edwardsport IGCC project. For example, if the application of BACT were to require the combustion of natural gas, rather than coal-derived syngas, in the plant's combustion turbines, it would dictate a fundamental change in the project design and purpose. The project is intended to provide for the generation of baseload electrical power through the combustion of syngas produced from local coal sources. Not only would the ability to produce syngas be lost under such an interpretation of BACT, which would negate the central focus of the facility, but it would also require a redesign and specification of the combustion turbines to be employed at the plant. Though the combustion turbines to be used at the Edwardsport generating facility are capable of combusting natural gas, they are specifically designed to enhance combustion efficiency when syngas, rather than natural gas, is being combusted. Conversion of the plant to a natural gas-burning generation facility would necessitate a different turbine design.

For nearly twenty years, U.S. EPA guidance and court decisions have made clear that the application of BACT does not compel a source to "redefine" its project. This "redefining the source" policy was first explained in *In re Pennsauken County, New Jersey, Resource Recovery Facility,* PSD Appeal No. 88-8 (Adm'r Nov. 10, 1988). This policy has most recently been reaffirmed by the Seventh Circuit Court of Appeals decision in *Sierra Club v. U.S. EPA,* No. 06-3907, 2007 WL 2406857 (7th Cir. Aug. 24, 2007), which involved the proposed construction of a coal-fired electric generating facility. The Prairie State Generating Company had proposed to construct a "mine-mouth plant" which would be constructed near a coal seam so that the coal from the seam could be transferred by conveyer belt to the electric generating plant. Opponents of the project appealed the BACT determination for the proposed facility, stating that the BACT analysis should have included the use of low-sulfur coal. The Court held that requiring the plant to burn low-sulfur coal which was not available from the nearby coal seam would require Prairie State to "arrange for it to be transported from mines more than a thousand miles away and…to make changes…to the design of the plant." Such a result, requiring the combustion of low-sulfur coal in place of the locally produced coal, the court held, is a difference in design rather than a difference in control technology and is not required by BACT. The same is true here: BACT does not require Duke Energy to redesign its project to forego the combustion of syngas at its proposed Edwardsport plant.

Similarly, Duke Energy proposed a cooling tower as the appropriate process technology for condensing of steam from the heat recovery steam turbine generators to be used in the combined cycle generating system at the Edwardsport IGCC plant. Also, Duke Energy proposed using low sulfur diesel fuel in the emergency generator and emergency fire pump; therefore, BACT was evaluated based on the use of diesel fuel rather than natural gas. In both these examples as well, a BACT analysis does not interfere with the project specification or design to employ a cooling tower or diesel fuel powered emergency equipment.

**Technical Comment 16:**

BACT limits should be expressed by energy output. As unit efficiency increases, total production decreases; therefore, BACT must consider efficiency of a unit and total pollution emissions, rather than merely focusing on emissions per unit of energy input. Increased efficiency is a pollution control method because it decreases the total amount of pollution emitted into the environment to produce electric power. IDEM should include output based emission limits in the final permit to ensure that efficient operation is implemented as a pollution control method.

**IDEM Response 16:**

There is no regulatory authority that mandates how a BACT limit should be expressed for an industry sector. When proposed BACT limits are evaluated, IDEM compares the equivalent emission rates of the proposed BACT limits to the BACT limits established at existing permitted facilities.

The following data regarding the pollutant emission rates was presented during the public meeting held on December 20, 2007:

| **Comparison of Pollution Levels Expressed by Energy Output** | | |
|---|---|---|
| **Pollutant** | **IGCC Plant** | **Existing Station** |
| CO | 0.40 lb/MW | 0.44 lb/MW |
| $NO_X$ | 0.73 lb/MW | 15.12 lb/MW |
| $SO_2$ | 0.124 lb/MW | 65.32 lb/MW |
| $PM/PM_{10}/PM_{2.5}$ | 0.160 lb/MW | 1.32 lb/MW |
| VOC | 0.014 lb/MW | 0.05 lb/MW |

In all cases, the proposed IGCC plant will operate more efficiently than the existing plant.

**Technical Comment 17:**

IDEM failed to conduct BACT analyses and establish BACT permit limits for $CO_2$ and $N_2O$.

**IDEM Response 17:**

Carbon dioxide ($CO_2$) and nitrous oxide ($N_2O$) are not regulated pollutants. The Best Achievable Control Technology (BACT) requirements are set out in 326 Indiana Administrative Code (IAC) 2-2 for the Prevention of Significant Deterioration (PSD) in New Source Review (NSR). The pollutants to be included in the BACT review under PSD are set out in the definition of "regulated NSR pollutants" at 326 IAC 2-2-1(uu). $CO_2$ and $N_2O$ do not meet the definition set out in 2-2-1(uu).

Consistent with the pronouncements of U.S. EPA on this subject, IDEM concludes that a BACT analysis is not required with respect to the projected emissions of $CO_2$ from Duke Energy's planned IGCC plant.

The Clean Air Act ("CAA") provisions establishing prevention of significant deterioration ("PSD") preconstruction permitting requirements for major sources specify that a BACT emission limit is required "for each pollutant subject to regulation" under the CAA (if proposed for emission at significant levels). 42 U.S.C. § 7475(a)(4); 42 U.S.C. § 7479(3). Carbon dioxide is not currently "subject to regulation" under the CAA. The U.S. Supreme Court's decision in Massachusetts et al v. Environmental Protection Agency et al., held merely that $CO_2$ was a "pollutant" and that the U.S. EPA must decide whether, or how, it should be regulated. The Court did not conclude that $CO_2$ is a pollutant "subject to regulation." In determining which pollutants are "subject to regulation" under the CAA, IDEM has followed the U.S. EPA interpretation that the phrase "subject to regulation" means pollutants that are subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant.

For reasons discussed below, the commenters' contention that carbon dioxide is "subject to regulation" under the CAA because certain Acid Rain regulations require sources to monitor and report their $CO_2$ emissions is contrary to law and the longstanding EPA interpretation of the meaning of that phrase. The phrase "subject to regulation," as used in the cited provisions within the CAA, is important since it triggers the requirement to install best available control technology ("BACT"). The phrase is not used elsewhere in the Act or its federal implementing regulations.

The U.S. EPA has consistently determined that a pollutant such as $CO_2$ is not a "pollutant subject to regulation" if the CAA did not require actual control of emissions of the pollutant. Moreover, this interpretation has been applied expressly to $CO_2$. The U.S. EPA's interpretation has been laid out in several guidance memoranda. For example, in a memorandum dated April 26, 1993 from Lydia N. Wegman, of U.S. EPA's Office of Air Quality Planning and Standards, to U.S. EPA's Regional Air Directors, it is specifically considered whether $CO_2$ was subject to regulation. The memorandum states that, although the 1990 amendments to the Clean Air Act included provisions addressing carbon dioxide and methane, "these requirements involve actions such as reporting and study, not actual control of emissions." The memorandum concluded, "if the results of these studies suggest the need for regulation, these pollutants could be reconsidered at that time for classification as pollutants subject to regulation under the Act." More recently, in 2002, the U.S. EPA substantially revised its New Source Review ("NSR") Program and promulgated revised rules on December 31, 2002. 67 *Fed. Reg.* 80290 (December 31, 2002). The revised rules substituted a new defined term, "regulated NSR pollutant" for the Act's phrase "pollutant subject to regulation." The phrase "regulated NSR pollutant" expressly includes only pollutants (or substances) (i) for which a national ambient air quality standard has been promulgated, (ii) that are subject to new source performance standards ("NSPS"), (iii) subject to a standard under the stratospheric ozone protection program of Title VI of the CAA, or (iv) that otherwise is subject to regulation under the Act (but generally excluding hazardous air pollutants). (Indiana's definition is essentially a verbatim replication of the federal definition)

The first three categories of the definition are similar in one aspect – they all provide for the development of substantive emission standards of the specified pollutants through a formal and comprehensive rulemaking approach. Carbon dioxide is not regulated under any of these three programs. This regulatory framework brings clarity to the fourth, catchall category, any pollutant "otherwise subject to regulation under the Act" (excluding hazardous air pollutants regulated under Section 112 of the Act). When viewed with the other three categories, it becomes clear that U.S. EPA did not intend the fourth category to include pollutants for which the Act does not require substantive emission limitations. This approach is consistent with a canon of statutory interpretation known as *ejusdem generis,* which provides that, where general words of description follow an enumeration of persons or things described by words of a particular and specific meaning, the general words are not to be construed in their widest extent, but are to be understood as applying only to persons or things of the same class or kind as those specifically mentioned or listed. Moreover, when the U.S. EPA added the term "regulated NSR pollutant" to the NSR rules in 2002, it listed in the preamble to the rule all the pollutants that it believed where currently regulated under the CAA. This list did not include $CO_2$.

The U.S. Environmental Appeals Board ("EAB") has expressly held that $CO_2$ is not "subject to regulation." In *In re Inter-Power of New York, Inc.,* 5 E.A.D. 130, 151 (EAB 1994), the EAB held that the U.S. EPA was not required to conduct a BACT analysis for $CO_2$ and hydrogen chloride because they were "unregulated pollutants." In *In re Kawaihae Cogeneration Project,* 7 E.A.D. 107, 132 (EAB 1997) the EAB again reviewed whether the U.S. EPA should have included BACT limits for $CO_2$. The EAB held that no limits were necessary because $CO_2$ was not considered "a regulated air pollutant for permitting purposes" because there were "no regulations or standards prohibiting, limiting, or controlling the emissions of greenhouse gases."

With the foregoing background, it is clear that, contrary to the commenters' remarks, Congress did not make $CO_2$ a pollutant "subject to regulation" when it enacted the provisions of Section 821 of Public Law 101-549. As a part of the 1990 Amendments to the Clean Air Act, Congress included a new title IV that established an acid rain control program. In the same legislation, Public Law 101-549, Congress also enacted Section 821, which, though not codified as a part of the Clean Air Act, contained requirements supplemental to Title IV whereby certain sources are to monitor and report their emissions of carbon dioxide. However, Sec. 821 does not require sources to limit or control their carbon dioxide emissions. When Congress enacted Sec. 821 of Public Law 101-549, it was fully aware of the U.S. EPA's interpretation that the phrase "subject to regulation" meant only pollutants that were subject to actual emission controls. If Congress had intended for the $CO_2$ monitoring and reporting requirements to trigger the requirement to perform a BACT analysis, it would have clarified the phrase "subject to regulation" in 42 U.S.C. § 7475(a)(4) to encompass pollutants that were not only subject to emission controls, but were also merely subject to monitoring and reporting requirements. The fact that Congress did not do so evinces their intent that these monitoring and reporting requirements would not subject $CO_2$ to a BACT analysis under PSD. In fact, this intention was articulated by one of the amendments sponsors, Congressman Cooper, who stated that his amendment "would not force any reductions right now." Statement of Congressman Cooper, House Debates on May 17, 1990, *reprinted in* Senate Committee on Environment and Public Works, Legislative History of Clean Air Act Amendments of 1990 (Comm. Print, Nov. 1993) at 2563.

Commenters' contention that a BACT analysis is required for nitrous oxide ($N_2O$) is in error for the same reasons. No provisions of the CAA or federal regulations adopted under the CAA expressly require or establish emission limits, standards or other controls for $N_2O$. Consequently, $N_2O$ is not "subject to regulation" under the CAA.

**Technical Comment 18:**

The effect of CO2 emissions from the proposed IGCC plant should be considered as a part of the collateral impacts analysis under BACT.

**IDEM Response 18:**

Under the top-down approach to BACT analysis, collateral environmental impacts are among the factors to be considered as part of step four of the analysis. EPA has described the purpose of the collateral impacts analysis as to "***temper*** the stringency of the technology requirements whenever one or more of the specified collateral impacts – energy, environmental, and economic – renders use of the most effective technique inappropriate." *Columbia Gulf Transmission Co.* 2 E.A.D. 824, 826 (EAB 1989). [Emphasis added.]

In its response to public comments in a recent PSD permit proceeding for the Bonanza WFCU facility proposed by the Deseret Power Electric Cooperative, U.S. EPA Region VIII remarked that the collateral impacts analysis is meant to focus on local environmental impacts that are "directly attributable to the proposed facility," and that the collateral impacts analysis is not the "appropriate mechanism for addressing the potential global impacts of $CO_2$ emissions from the Deseret Bonanza WFCU." EPA further stated that it has not previously considered the collateral impacts of $CO_2$ and other GHGs in setting the BACT levels in permits and also cited an Environmental Appeals Board decision, *Interpower of New York*, 5 E.A.D. 130 (1994), which held that the EPA did not have to consider $CO_2$ and other GHG emissions during its collateral impacts analysis.

## Public Comments - General

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:

**General Comment 1:**

IDEM erred in denying an extension to the comment period. IDEM should allow comments to be submitted by e-mail and telephone. The public should be given at least the same amount of time that IDEM had to prepare the draft permit. The public comment period started just before Thanksgiving and ends on New Year's Eve. The public needs more time during the already busy holiday season. IDEM has always granted extensions of the public notice period in the past. Since this is the first Integrated Gasification and Combine Cycle (IGCC) plant proposed for Indiana, IDEM should have allowed more time for public review. IDEM should grant a sixty extension of the public comment period.

**IDEM Response 1:**

OAQ notified the public that the two draft permits were available for public comment in a mailing sent out on November 16, 2007 and a public notice published in the Sun-Commercial newspaper on November 18, 2007. The draft permit documents were made available for review at the Knox County Library, 502 N. 7th Street, Vincennes, at IDEM's Southwest Regional Office, 1120 N. Vincennes Ave., Petersburg, at IDEM's main office in Indianapolis and at http://www.in.gov/idem/permits/air/pending.html on the internet. On November 18, 2007, IDEM also issued a notice that it would conduct a public hearing and public meeting regarding the draft permits on December 20, 2007, in Bicknell, at the North Knox High School auditorium. The public comment period ended on December 31, 2007.

After receiving requests to extend the comment period, IDEM issued a letter to concerned parties on December 10, 2007 stating that after considering the requests, IDEM decided that the end of the public comment period would not be further extended. The letter did note that comments could be submitted by e-mail and gave the e-mail address. IDEM considers all written comments, whether they are submitted in hardcopy or electronically. Under Indiana's air permit rules, specifically 326 Indiana Administrative Code 2-7-17, OAQ gives the public at least 30 days to submit written comments. In the original public notice OAQ set the pubic comment period deadline at December 31, 2007, much longer than 30 days.

IDEM believes that the length of the comment period was sufficient and appropriate. IDEM received a substantial number of comments within the public comment period, including numerous comments sent by e-mail and oral comments submitted during the public hearing. The attached list of commenters sets out the names of the persons and organizations that commented on this permit. The technical comments IDEM received were very detailed and thorough showing extensive review of the draft permit documents. Two of the technical commenters also had previous experience reviewing and commenting on a similar IGCC project. In June 2007, the Sierra Club and Valley Watch, Inc. submitted detailed technical comments to the Commonwealth of Kentucky regarding the Cash Creek Generation, LLC, a 770 megawatt IGCC power plant. The Cash Creek public comment period was limited to thirty days.

**General Comment 2:**

IDEM should have scheduled the public hearing for a more reasonable date. IDEM should not conduct a public hearing just prior to Christmas. IDEM should not conduct a public hearing during the holiday season. IDEM should conduct a second public hearing.

**IDEM Response 2:**

IDEM gave more than 30 days notice of the public meeting and public hearing that were held on December 20, 2007. The meeting and hearing were held at the North Knox High School auditorium in Bicknell, beginning at 5:30pm. Over 600 people attended the meeting and public hearing. During the public meeting IDEM gave a presentation regarding IGCC, the draft permits and the expected emissions. IDEM also answered questions from the audience during the public meeting. IDEM ended the public meeting when there were no further questions. After a short break, IDEM began the public hearing. During the public hearing IDEM received comments from every person that indicated that they wished to make comments. Twenty-five persons presented comments during the public hearing resulting in a written transcript of over sixty pages. Due to the high number of persons who attended the public meeting and public hearing, as well as the high number of those who actively participated, IDEM believes that the December 20 public meeting and public hearing provided very appropriate and sufficient public participation. IDEM believes that the date of the meeting/hearing was not a deciding factor for anyone who did not choose to attend.

**General Comment 3:**

The proposed plant will emit greenhouse gases at rates that do not protect health or the environment. Indiana is number one in the per capita emissions of carbon. The proposed IGCC plant will emit increase carbon dioxide emissions by 3.5 million tons per year. Greenhouse gas emissions are causing an accelerated global warming. Global warming will cause catastrophic environmental conditions, including drought, flooding, more severe storms, famine, pandemic disease, death, higher temperatures, and a rise in ocean levels that will displace hundreds of millions of people. Greenhouse gas emissions will substantially endanger public health and the environment. IDEM should be a leader in climate protection. IDEM should follow the lead of the Kansas Department of Health and Environment and reject this project based on the carbon dioxide emissions. IDEM should watch the movie "An Inconvenient Truth" by Al Gore. The Intergovernmental Panel on Climate Change shows that carbon dioxide is causing drastic climate destabilization. The Nation Research Council has identified carbon dioxide as causing a human induced forcing of climate change in its 2001 report.

The proposed plant will have a lower emission rate for carbon dioxide than the current 160-megawatt plant.

**IDEM Response 3:**

As stated in IDEM's response to Technical Comment 17, carbon dioxide, as well as other greenhouse gases, are not regulated pollutants under Indiana law. IDEM applies the rules contained in title 326 of the Indiana Administrative Code.

**General Comment 4:**

IDEM should follow the United States Supreme Court ruling in Mass. v. EPA, which found that carbon dioxide is a regulated air pollutant. IDEM should delay this project until carbon regulations are in place.

**IDEM Response 4:**

The United States Supreme Court case of Massachusetts et al v. Environmental Protection Agency et al. was brought by several states to force the U.S. Environmental Protection Agency to pass regulations pursuant to section 202(a)(1) of the federal Clean Air Act to regulate the emission of carbon dioxide from new motor vehicles. As stated in IDEM's response to Technical Comment 17, the U.S. Supreme Court's decision in *Massachusetts v. EPA* held that $CO_2$ was a "pollutant" but did not find that it was a "regulated air pollutant." Rather, the Court held that the U.S. EPA must decide whether, or how, it should be regulated. There have been no carbon or carbon dioxide regulations proposed by the U.S. EPA or pending before the Indiana Air Pollution Control Board that would affect the permits for the proposed IGCC plant.

**General Comment 5:**

Carbon sequestration is not a proven technology. We cannot gamble on an untested technology because of the threat of global warming. The Indiana Geological Survey has not yet identified a suitable and safe carbon sequestration site. Commercially viable carbon sequestration is more than 15 years away.

**IDEM Response 5:**

This permit does not require carbon sequestration. As stated in the response to *Technical Comment 17* (pages 43-45), IDEM does not regulate emissions of carbon dioxide.

**General Comment 6:**

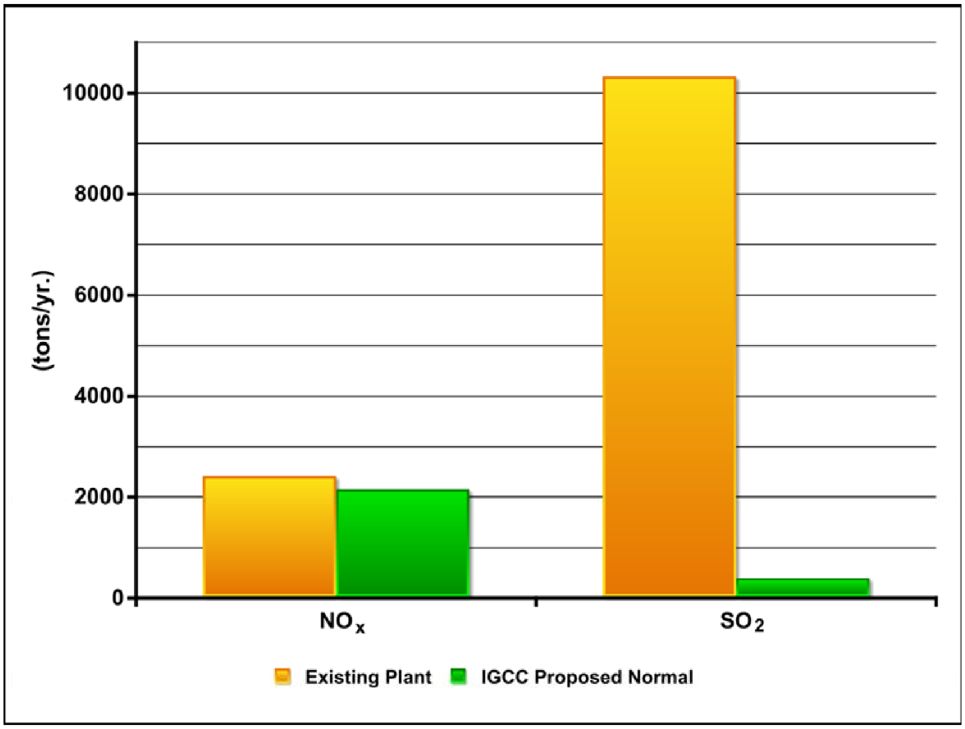
*IDEM received both positive and negative comments on the following issue and both are presented here:*

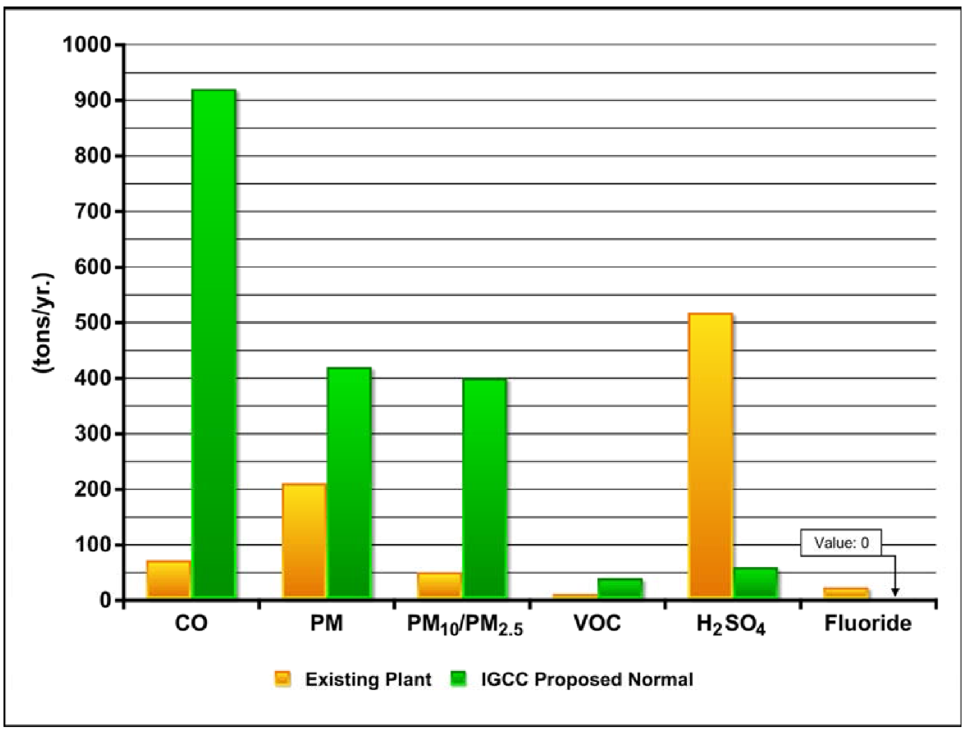
Coal pollution results in too many deaths already. This plant will result in health consequences for Indiana citizens. Indiana is 5$^{th}$ in deaths linked to coal pollution. Indianapolis is the 9$^{th}$ most polluted city. This plant will impact public health. Continuing to pollute will lead to higher rates of asthma, heart disease and other illnesses. My health has already been affected by mercury emissions. Many people in the Evansville area already have allergy and lung ailments. Our children and future generations will lose the enjoyment of the great outdoors due to environmental issues. Governor Daniels is a Christian who is obligated by his faith to care for creation.

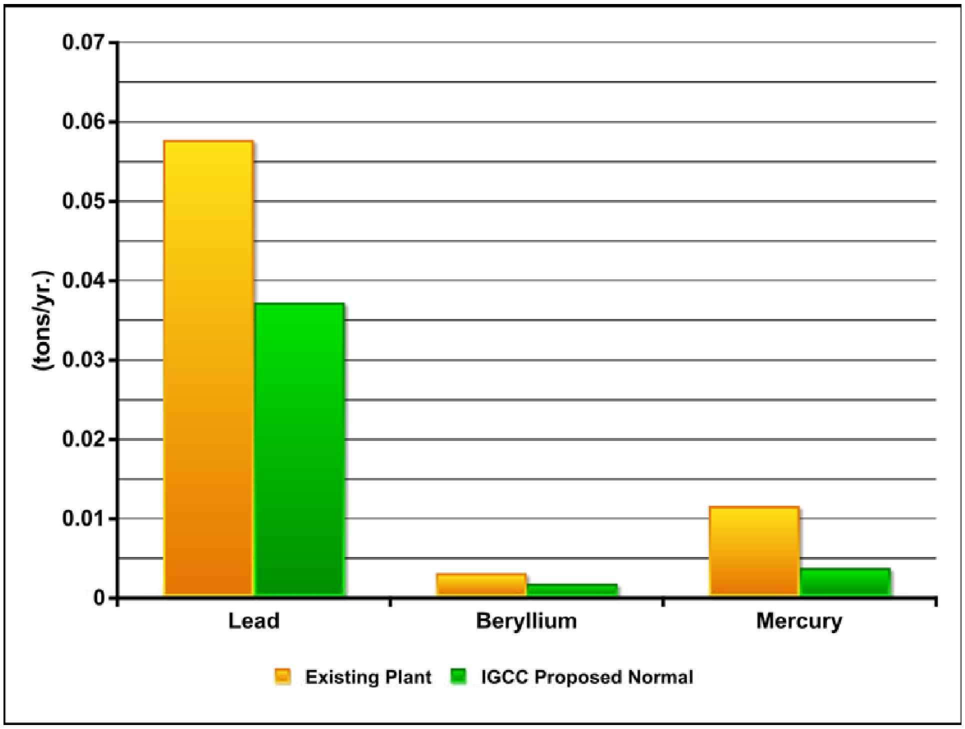
This plant will be safer and cleaner than the current plant. This plant will reduce the total amount of pollution released into the air. The new plant will provide four times as much electricity and will emit less pollution. The new plant and the shut down of the current plant will provide a better environment. Indiana has a serious problem with mercury contamination in our fish. The IGCC plant will remove virtually all of the mercury. This will help us begin to turn the corner on reducing mercury contamination from coal-fired power plant.

**IDEM Response 6:**

The IGCC plant's permits require the current power plant to shut down. This will result in a net decrease of many pollutants, including an approximately 10,000 tons per year reduction in sulfur dioxide. As stated above and illustrated in *Technical Comment and Response 16* (page 40), the new plant will be more energy efficient, producing much less pollution per megawatt of power produced. The net emission changes are illustrated by the following graphs:


(tons/yr.)
10000
8000
6000
4000
2000
0
$NO_x$
$SO_2$
Existing Plant
IGCC Proposed Normal


(tons/yr.)
1000
900
800
700
600
500
400
300
200
100
0
Value: 0
CO
PM
$PM_{10}/PM_{2.5}$
VOC
$H_2SO_4$
Fluoride
Existing Plant
IGCC Proposed Normal




The federal Clean Air Act requires the United States Environmental Protection Agency (U.S. EPA) to set National Ambient Air Quality Standards (NAAQS) for six criteria pollutants. These criteria pollutants are carbon monoxide (CO), lead, sulfur dioxide ($SO_2$), particulate matter to a diameter of 2.5 microns ($PM_{2.5}$), nitrogen oxides ($NO_X$) and ground level ozone ($O_3$). The U.S. EPA sets these standards at levels that protect human health, which is why the NAAQS are often referred to as the federal health standards for outdoor air. The NAAQS limit for all criteria pollutants is set low enough to protect human health, including the health of sensitive persons, such as asthmatics, children, and the elderly. More information about each of these pollutants is available at http://www.epa.gov/air/airpollutants.html on U.S. EPA's website. The complete table of the NAAQS for all six criteria pollutants can be found at the http://www.epa.gov/air/criteria.html website. EPA's website http://www.epa.gov/air/urbanair/6poll.html provides more detailed information about the health effects of these six common air pollutants and why they are regulated.

The federal Clean Air Act requires the United States Environmental Protection Agency (U.S. EPA) to determine whether the ambient air in any area of the United States fails to meet any of the National Ambient Air Quality Standards (NAAQS). Any area that fails to meet one or more of the NAAQS will be designated as in "nonattainment" for that pollutant. Large air pollution sources in a nonattainment area are subject to additional regulations and U.S. EPA may require that additional steps be taken that will result in the area meeting the NAAQS.

Knox County is in attainment for all the NAAQS. Information about current and expected air pollution levels is available on IDEM's SmogWatch site at http://www.in.gov on the internet. The site is designed to provide Hoosiers with an easy-to-read forecast of air quality in their communities. The site provides information about ground-level ozone and particulate matter forecasts.

IDEM conducted a refined air quality modeling analysis that showed that the IGCC plant will not cause a violation of the NAAQS. A Hazardous Air Pollutant (HAP) analysis was also performed. This study looked at the cancer risk and non-cancer health effects of the proposed IGCC plant. The modeling results show that the IGCC plant will not pose a health hazard. The additive cancer risk estimate from all the HAPs that could be released is less than one additional cancer case in one million people. This means if an individual was exposed to the emissions continuously for 70 years, the risk of getting cancer from this exposure would be less than one in a million. The United Stated Environmental Protection Agency considers one in ten thousand excess cancer risks to be the upper range of acceptability with an ample margin of safety. A complete description of the air quality analysis is included in Appendix C to the original Technical Support Document.

**General Comment 7:**

Indiana has been identified as a leading cause of acid rain.

**IDEM Response 7:**

Acid rain is a serious environmental problem that affects large parts of the United States and Canada. Acid rain is particularly damaging to lakes, streams, and forests and the plants and animals that live in these ecosystems. The Edwardsport facility has an Acid Deposition Control permit which regulates its emissions of sulfur dioxide and oxides of nitrogen under the Acid Rain Program. The IGCC plant will also be regulated under the Acid Rain Program. The IGCC plant will reduce the total amount of NOx and significantly reduce the total amount of $SO_2$ emitted, as discussed in the response to General Comment 6, above. These reductions will reduce the amount of acidic precipitation caused by this plant. More information about the acid rain program is available at http://www.epa.gov/acidrain on the internet.

The provisions of the Clean Air Interstate Rule (CAIR) program take effect in 2009. The rule provides states with a solution to the problem of power plant pollution that drifts from one state to another. CAIR covers 28 eastern states and the District of Columbia. The rule uses a cap and trade system to reduce the target pollutants, sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_x$), by 70 percent.These reductions will also reduce the amount of acidic precipitation caused by industry in Indiana. All CAIR permit applications are due to IDEM by April 5, 2008. Some sources have already submitted their CAIR applications and IDEM is processing those applications. Information about the CAIR program is available at http://www.in.gov/idem and http://www.epa.gov/airmarkets/progsregs/cair on the internet.

**General Comment 8:**

IDEM's endangered species analysis should have included a specific analysis of the impact on the 54 endangered species known to exist in Knox County. IDEM is required to consult with the United States Fish & Wildlife Service regarding impacts on endangered species. IDEM did not include the impact on endangered species like Staghorn Coral and Elkhorn Coral that are threatened by global warming.

**IDEM Response 8:**

As stated in the Technical Support Document, federal and state endangered or threatened animal species are listed by the U.S. Fish and Wildlife Service; Division of Endangered Species for Indiana and include 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.

IDEM is not required to complete a specific analysis for each of the threatened species. IDEM is not required to consult with the U.S. Fish & Wildlife Service since U.S. EPA has delegated to IDEM the full authority to administer the permitting program for major sources of air pollution.

IDEM's endangered species act analysis is limited to species in the area around the plant that will be impacted by increased amounts of regulated pollutants. As discussed above, IDEM does not regulate carbon dioxide or methane, the principle gases of concern for global warming. In addition, Staghorn Coral and Elkhorn Coral exist only in warm, shallow ocean waters. There is no such environment in Indiana or any surrounding state that would be impacted by the regulated pollutants from this plant.

**General Comment 9:**

Valley Watch, Inc. made the following comments: IDEM's attitude has changed from one of mere indifference to environmental protection to one of hostility toward the concept of protection of the environment or human health. This permit is a clear manifestation of that change. Indiana does not consider the federal Clean Air Act germane or applicable to Indiana. IDEM makes every effort to narrowly define rules and laws to benefit polluters and raise health risks for citizens. IDEM's Commissioner has indicated that the agency has an economic development function that he sees as co-equal to its function to enforce environmental laws. Indiana does not consider the federal Clean Air Act as applicable to the state.

**IDEM Response 9:**

As discussed above, the permits for the IGCC plant will protect human health and the environment and result in a reduction of thousands of tons of regulated pollutants, including a reduction in all hazardous air pollutants. IDEM has incorporated into the permits all the applicable requirements from the air pollution control rules found in Title 326 of the Indiana Administrative Code (IAC). These rules are discussed in the Technical Support Document and are included as federally enforceable permit terms and conditions in the permits. The air pollution control rules were adopted by the Indiana Air Pollution Control Board (and its predecessor) pursuant to the statutory authority granted by the Indiana legislature. This grant of rule making authority is found principally at Indiana Code (IC) 13-15-2-1 as well as in other statutory provisions.

The federal Clean Air Act is important to environmental regulation in Indiana. The Act sets out the authority that the U.S. Environmental Protection Agency has to pass regulations to control pollution. When setting out new air pollution control regulations U.S. EPA usually requires Indiana to pass corresponding regulations that are at least as strict. U.S. EPA then reviews Indiana's new regulations to make sure they achieve at least the same level of pollution control as the federal rule.

Indiana's environmental policy is set out by statute at IC 13-12-3-1, which states:

The purpose of this title is:

(1) to provide for evolving polices for comprehensive environmental development and control on a statewide basis;

(2) to unify, coordinate, and implement programs to provide for the most beneficial use of the resources of Indiana, and

(3) to preserve, protect, and enhance the quality of the environment so that, to the extent possible, future generations will be ensured clean air, clean water, and a healthful environment.

**General Comment 10:**

Valley Watch, Inc. commented that it had requested pre-construction monitoring information since 2006. It was not given the pre-construction monitoring data it had requested until just a few weeks prior to the issuance of the permit. The information it received from IDEM was gibberish.

**IDEM Response 10:**

IDEM sent the monitoring information to Valley Watch, Inc. soon after IDEM received the information. The monitoring information can be understood if used in the AERMOD software program. The AERMOD modeling system is a steady-state plume model that incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain. The AERMOD program is available free from the U.S. EPA at http://www.epa.gov/scram001/dispersion_prefrec.htm on the internet. There is also an instruction manual available at that website.

**General Comment 11:**

The technology for this plant, Integrated Gasification, is new and untried.

IGCC is the best science available in the world. Further research will lead to improvements in the years to come. PSI Energy was a major contributor to the U.S. Department of Energy's coal gasification project at Wabash River Energy in Terre Haute. The IGCC plant will produce electricity more efficiently and result in less coal waste, the use of less water and the production of sulfur as a useable byproduct.

**IDEM Response 11:**

Coal gasification is a proven technology. It has been employed at the U.S. Department of Energy's coal gasification project at Wabash River Energy in Terre Haute for many years. The experience gained from that project has lead to many improvements and refinements in this technology. As set out in IDEM's Best Achievable Control Technology (BACT) analysis in Appendix B of the original Technical Support Document, there is also an operating coal gasification 260-megawatt power plant known as Tampa Electric Company – Polk Power in Florida. Florida also issued a permit to Orlando Utilities Commission – Curtis H. Stanton Energy Center for a 285-megawatt IGCC plant in December of 2006. Illinois issued a permit to Christian County Generation, LLC for the Taylorville Energy Center 677 megawatt IGCC plant in June of 2007. Kentucky issued a permit to Cash Creek Generation, LLC for the Cash Creek Generating Station, a 770-megawatt IGCC plant on November 30, 2007.

**General Comment 12:**

Many people and organizations commented on the following:

- whether alternative ways to generate electricity should be used,
- the amount of water that will be used by the plant,
- whether permitting issues should be handled locally,
- how the cost of the plant should be considered,
- whether coal gasification will be economically viable in the future, and
- the effect of the plant on the local and state economies, tax base, energy costs, future development, local infrastructure, job creation, and quality of life.

**IDEM Response 12:**

OAQ recognizes that these concerns are important to those who expressed them; however, they do not have a direct impact on how IDEM reviews and makes decisions on air permit applications. IDEM, OAQ's permit review by law cannot address issues for which it does not have direct regulatory authority.

**Other Changes**

Upon further review, the OAQ has decided to make the following revisions to the permit:

**Change No. 1:**

The location address stated on the title page of the permit and in Condition A.1 was outdated and has been corrected as follows.

**~~State Road 67~~ 15424 East State Road 358**

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

Source Address: ~~State Road 67~~ **15424 East State Road 358**, Edwardsport, Indiana 47258

**Change No. 2:**

IDEM has revised the emission unit descriptions for the power block cooling tower (Condition A.2, paragraph (B)(b)(3)) as follows:

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

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

(b) One power block consisting of the following:

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

**Change No. 3:**

IDEM has clarified the General Record Keeping Requirements pertaining to "reasonable possibility" in Condition C.20 (original paragraph (c), now paragraphs (c) and (d)) as follows:

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

~~(c) If there is a “project” (as defined in 326 IAC 2-2-1(qq)) 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)) 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 IAC 2-3-1(mm)), the Permittee shall comply with following:~~

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

~~(A) A description of the project.~~

~~(B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project.~~

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

~~(i) Baseline actual emissions;~~

~~(ii) Projected actual emissions;~~

~~(iii) Amount of emissions excluded under section 326 IAC 2-2-1(rr)(2)(A)(iii) and/or 326 IAC 2-3-1(mm)(2)(A)(iii); and~~

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

~~(2) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (1)(B) above; and~~

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

**(c) 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.**

**Change No. 4:**

IDEM has updated the General Reporting Requirements in Condition C.21, paragraphs (f), (f)(2), (g) and (h)(2) as follows to correct the references to Condition C.20:

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]

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(f) If the Permittee is required to comply with the recordkeeping provisions of ~~(c)~~ **(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:

(2) Submit a report to IDEM, OAQ within sixty (60) days after the end of each year during which records are generated in accordance with ~~(c)(2) and (3)~~ **(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.

(g) If the Permittee is required to comply with the recordkeeping provisions of ~~(c)~~ **(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:

(h)

(2) The annual emissions calculated in accordance with ~~(c)(2) and (3)~~ **(d)(1) and (2)** in Section C - General Record Keeping Requirements.

**IDEM Contact**

Questions regarding this proposed permit can be directed to:

Kimberly Cottrell
Indiana Department Environmental Management
Office of Air Quality
100 North Senate Avenue
MC 61-53, Room 1003
Indianapolis, Indiana 46204-2251
Toll free (within Indiana): 1-800-451-6027 extension 3-0870
Or dial directly: (317) 233-0870
kcottrel@idem.in.gov

Please refer to Significant Source Modification No.: 083-23529-00003 and Significant Permit Modification No.: 083-23531-00003 in all correspondence.

# Indiana Department of Environmental Management
# Office of Air Quality

## Appendix A to the
## Addendum to the Technical Support Document (TSD)
## Commenter List

### Source Description and Location

| | |
|---|---|
| Company Name: | Duke Energy Indiana - Edwardsport Generating Station |
| Address City IN Zip: | 15424 East State Road 358, Edwardsport, Indiana 47258 |
| County: | Knox |
| SIC / NAICS Code: | 4911 |
| Operation Permit No.: | T 083-7243-00003 |
| Operation Permit Issuance Date: | August 10, 2004 |
| Source Modification No.: | 083-23529-00003 |
| Permit Modification No.: | 083-23531-00003 |
| Permit Reviewer: | Kimberly Cottrell |
| Date: | January 23, 2008 |

### Commenter List

The names of each person that submitted written comments on the draft permits are listed below in alphabetical order.

**Commenter Information**

Joanne M. Alexandrovich, Ozone Officer, Vanderburgh County Health Department, Evansville, IN
Deborah A. Allmayer, Indiana University, Bloomington, IN
Mary Andrus-Overley, citizen, Bloomington, IN
Arlis Bates, citizen, Hillsboro, IL
Kreg Battles, Representative, District 64, State of Indiana House of Representatives, Indianapolis, IN
May Batz, citizen, Bloomington, IN
Shyla Beam, Executive Director, Vincennes Convention and Visitors Bureau, Vincennes, IN
Marilyn H. Bedford, citizen, Indianapolis, IN
Christine Belt, citizen, Evansville, IN
David C. Bender, Garvey McNeil & McGillivray, S.C., representing Sierra Club, Valley Watch, and Citizen Action Coalition, Madison, IN
Patricia Biddinger, citizen, Indianapolis, IN
Terrence Black, Green Way Supply, Indianapolis, IN
John Blair, citizen, Evansville, IN
Steven M. Blinn, VP Commercial Loans, Old National Bank, ,
Mary Blizzard, citizen, Bloomington, IN
Jim Bobe, Knox County Commissioner, Vincennes, IN
Susan Bookout, citizen, Bloomington, IN
Valerie Boots, citizen, Indianapolis, IN
Emily Bowles, citizen, Bloomington, IN
Brenda Bragg, citizen, Columbus, IN
Glenda Breeder, citizen, Spencer, IN
Greg Buck, Director, Campaign for Sustainable Economics, Indianapolis, IN
Carol Burke, citizen, ,
Peter Cahn, citizen, ,

**Commenter Information**

Susan Cahn, citizen, ,
Greg Cardinal, First American Bank, Vincennes, IN
Duane H. Chattin, Vincennes City Council, Vincennes, IN
Corrie E. Cook, citizen, ,
Karren Coplan, Indiana Green Party, Indianapolis, IN
John F. Crosby, , ,
David L. Culp, citizen, Vincennes, IN
Elizabeth Curtis, citizen, Bicknell, IN
Kevin Curtis, citizen, Bicknell, IN
Beth Deane, citizen, ,
Greg Deaves, Market Manager, Sherwin-Williams #1211, Vincennes, IN
Stephen W. Dillon, citizen, ,
Thomas Doane, Jones & Sons, Inc., Vincennes, IN
Karen L. Dopkins, citizen, Fishers, IN
Linda Duke, citizen, Indianapolis, IN
Tom E. Duncan, citizen, Indianapolis, IN
Linda Dyer, citizen, Evansville, IN
Rebecca Edlin, citizen, ,
Janet Ellis, citizen, Noblesville, IN
Pat Ertel, citizen, ,
Edgar Fehnel, citizen, ,
Amanda M. Figolah, citizen, Fishers, IN
Michael A. Fischer, citizen, Indianapolis, IN
Gregory Foote, citizen, Indianapolis, IN
Willard A. Freeman, citizen, Nashville, IN
Gary L. Gentry, President, Knox County Development Corporation, Vincennes, IN
Carmen Giron, citizen, Melrose Park, IL
James H. Gislason, Risk Management Consultants, Vincennes, IN
Jane Goodman, citizen, Bloomington, IN
Vincent Griffin, VP of Environmental and Energy Policy, Indiana Chamber of Commerce, Indianapolis, IN
Colleen M. Haas, citizen, Bloomington, IN
Avrom Handleman, citizen, ,
Douglas R. Hatton, citizen, Westfield, IN
Mary Lou Hatton, citizen, Westfield, IN
Anne J. Haynes, citizen, Bloomington, IN
Christopher Haynes, citizen, Bloomington, IN
Mary Helfer, citizen, Hillsboro, IL
Richard E. Helton, President, Vincennes University, Vincennes, IN
Kent E. Hert, citizen, Springville, IN
Christopher J. Hertel, citizen, Knox County, IN
A. John Hidde, citizen, Vincennes, IN
Laura Hildreth, citizen, ,
Jason Hill, citizen, Bloomington, IN
Mark R. Hill, President Pro Tempore, City of Vincennes - Common Council, Vincennes, IN
Joann S. Hoadley, citizen, Bloomingon, IN
John E. Hoadley, citizen, Bloomingon, IN
Beth H. Hollingsworth, citizen, Bloomington, IN
Thomas H. Hollingsworth, citizen, Bloomington, IN
Judith Hostetler, citizen, Indianapolis, IN
Gary Houdek, citizen, Indianapolis, IN
Heliene Houdek, citizen, Indianapolis, IN
Phil Hoy, citizen, Indianapolis, IN

**Commenter Information**

John Hylton, citizen, Plainfield, IN
Anne Jacoby, Generations, Vincennes, IN
Lynn Jenkins, citizen, Zionsville, IN
Edwin P. Jensen, citizen, Bloomington, IN
Monica F.K. Jensen, citizen, Bloomington, IN
Dee Johnson, citizen, Nineveh, IN
Elizabeth Joshi, citizen, Newburgh, IN
Linda Joyner, citizen, Indianapolis, IN
Chris Judge, citizen, Bloomington, IN
Lilly Judge, citizen, , IN
Larry Kane, Bingham McHale, LLP on behalf of Duke Energy Indiana, Indianapolis, IN
Velda Kanne, citizen, Bloomington, IN
Rev. Georg Karl, Pastor, First Church of God in Vincennes, Vincennes, IN
Joan Keeler, citizen, Bloomington, IN
David Keppel, citizen, Bloomington, IN
Tim Kiger, Schott North America, Vincennes, IN
Jean L. Kraft, citizen, Carmel, IN
Grey Larsen, citizen, Bloomington, IN
Robert K. Lechner, President, Knox County Council, Vincennes, IN
Angela Lexmond, citizen, Bloomington, IN
Jim Lingenfelter, Five2Five Design Studio, LLC, Indianapolis, IN
Jennifer Livesay, citizen, Bloomington, IN
Terry Loacks, citizen, ,
Carl W. Lowry, citizen, Noblesville, IN
Marc McNeece, Knox County Chamber of Commerce, Vincennes, IN
Mary Meyer, Indiana Green Party, Indianapolis, IN
Shawndra Miller, citizen, ,
Carolyn A. Mitchell, citizen, Bloomington, IN
Peter M. Mitchell, citizen, Bloomington, IN
Armin Moczek, citizen, Bloomington, IN
Laura Mojonnier, citizen, Bloomington, IN
Linda Montag-Olson, citizen, Zionsville, IN
Terry Mooney, Mayor, City of Vincennes, Vincennes, IN
Andrew P. Myszak, President, Myszak + Palmer, Inc., Vincennes, IN
Darcia Narvaez, Director, Center for Ethical Education (CEE), University of Notre Dame, Notre Dame, IN
Martha Jane Neufelder, citizen, Columbus, IN
Jennifer Nulph, citizen, Columbus, IN
Mary Beth O'Brien, citizen, Nashville, IN
Tammy J. Orahood, citizen, Bloomington, IN
Elizabeth Page, citizen, Indianapolis, IN
James R. Parish, President, Knox County Commissioners, Vincennes, IN
Isabel Piedmont, Bloomington City Council, Bloomington, IN
David Pilbrow, citizen, Indianapolis, IN
Ken Pimple, citizen, Bloomington, IN
Sam Portanova, U.S. EPA, Region 5, Chicago, IL
Deborah Quinto, citizen, Indianapolis, IN
Julie L. Rhodes, JLR Consulting, Indianapolis, IN
Austin Ritterspach, citizen, ,
Arthur Ross, Sr., citizen, Ferdinand, IN
Jeanette Rowe, citizen, Indianapolis, IN
Kevin W. Rowland, President, Stradtner, Rowland & Associates, Inc., Vincennes, IN
Michael Ryan, citizen, Indianapolis, IN

**Commenter Information**

Kim Sackmann, citizen, Unionville, IN
Martha Sattinger, citizen, Bloomington, IN
Matthew Schaefer, citizen, Indianapolis, IN
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Thomas M. Trowbridge, Mayor, City of Bicknell, Bicknell, IN
Allison Tucker, Saint Joseph Regional Medical Center, South Bend, IN
Kent E. Utt, Community Bank President, Regions Bank, Vincennes, IN
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Marcia Veldman, citizen, Bloomington, IN
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# Indiana Department of Environmental Management
# Office of Air Quality

## Technical Support Document (TSD)
## Significant Source Modification (SSM) of a Part 70 Source
## Significant Permit Modification (SPM) of Part 70 Operating Permit

### Source Description and Location

| | |
|---|---|
| Source Name: | Duke Energy Indiana – Edwardsport Generating Station |
| Source Location: | 15424 East State Road 358, Edwardsport, Indiana 47258 |
| County: | Knox |
| SIC Code: | 4911 |
| Operation Permit No.: | T 083-7243-00003 |
| Operation Permit Issuance Date: | August 10, 2004 |
| Significant Source Modification No.: | SSM 083-23529-00003 |
| Significant Permit Modification No.: | SPM 083-23531-00003 |
| Permit Reviewer: | Kimberly Cottrell |

### Source Definition

The location of the Integrated Gasification and Combined Cycle (IGCC) power plant is contiguous to the location of the current operations at Duke Energy Indiana - Edwardsport Generating Station, and has the same SIC code as the current power plant. Therefore, the IGCC plant has been determined to be part of the existing source (Edwardsport Generating Station).

### Existing Approvals

The source (Edwardsport Generating Station) was issued Part 70 Operating Permit No. 083-7243-00003 on August 10, 2004. The source has since received the following approvals:

(a) Acid Rain Administrative Amendment No. 083-10322-00003, issued on August 12, 2004;

(b) Significant Permit Modification No. 083-17006-00003, issued on June 7, 2006;

(c) Acid Rain Renewal No. 083-19349-00003, issued on July 17, 2006; and

(d) Acid Rain Renewal No. 083-24145-00003, issued on July 9, 2007.

### County Attainment Status

The source is located in Knox County. The attainment status of the county is defined in Table 1 below:

**Table 1: County Attainment Status**

| Pollutant | Status |
|---|---|
| CO | attainment |

| **Table 1: County Attainment Status** | |
|---|---|
| **Pollutant** | **Status** |
| Lead | attainment |
| $NO_2$ | attainment |
| $PM_{10}$ | attainment |
| $PM_{2.5}$ | attainment |
| $SO_2$ | attainment |
| 8-hour Ozone | attainment |

(a) Volatile organic compounds (VOC) and nitrogen oxides ($NO_X$) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and $NO_X$ emissions are considered when evaluating the rule applicability relating to ozone. Knox County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and $NO_X$ emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) Knox County has been classified as attainment for $PM_{2.5}$. U.S. EPA has not yet established the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 for $PM_{2.5}$ emissions. Therefore, until the U.S.EPA adopts specific provisions for PSD review for $PM_{2.5}$ emissions, it has directed states to regulate $PM_{10}$ emissions as a surrogate for $PM_{2.5}$ emissions.

(c) Knox County has been classified as attainment or unclassifiable for $PM_{10}$, $SO_2$, $NO_2$, CO, and Lead. 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) 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

Table 2 below summarizes the potential to emit of the entire source (existing source - Edwardsport Generating Station), prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

| **Table 2: Source Status PTE** | |
|---|---|
| **Pollutant** | **Emissions** (ton/yr) |
| CO | > 100 |
| $NO_X$ | > 100 |
| PM | > 100 |
| $PM_{2.5}$ | > 100 |
| $PM_{10}$ | > 100 |
| $SO_2$ | > 100 |

**Table 2: Source Status PTE**

| **Pollutant** | **Emissions** (ton/yr) |
|---|---|
| VOC | > 100 |
| Single HAP | > 10 |
| Total HAP | > 25 |

(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 the Part 70 Operating Permit No.T083-7243-00003, issued on August 10, 2004.

(c) 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).

## Actual Emissions

Table 3 shows the actual emissions from the existing source (Edwardsport Generating Station). This information reflects the 2006 OAQ emission data.

**Table 3: Actual Emissions**

| **Pollutant** | **Actual Emissions** (ton/yr) |
|---|---|
| CO | 19.3 |
| $NO_X$ | 589.9 |
| PM | 41.75 |
| $PM_{10}$ | 6.04 |
| $PM_{2.5}$ | 3.03 |
| $SO_2$ | 3,325.3 |
| VOC | 2.69 |
| HAP Cadmium (Cd) | $2.3 \times 10^{-5}$ |
| HAP Lead (Pb) | 0.016 |
| HAP Hydrochloric Acid (HCl) | 45.93 |
| HAP Hydrogen Fluoride (HF) | 5.74 |
| HAP Mercury (Hg) | 0.016 |
| Total HAPs | 51.70 |

## Proposed Modification

On August 18, 2006, the Office of Air Quality (OAQ) received an application from Duke Energy Indiana to construct and operate an Integrated Gasification and Combined Cycle (IGCC) electric generating plant at the Edwardsport generating station site, located at State Road 67, Edwardsport, Indiana, in Knox County. The IGCC plant would replace the existing electric generating equipment at the Edwardsport Generating Station. The Edwardsport Generating Station is classified as a major stationary source since the station is defined 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", and is located in an attainment or unclassified area as designated in 326 IAC 1-4 and that emits, or has the potential to emit, one hundred (100) tons per year or more of any regulated NSR pollutant (326 IAC 2-2-1(gg)(1).

The proposed IGCC project is considered a modification to an existing major stationary source and was evaluated under 326 IAC 2-2-2(D)(1) and (2) to determine whether or not the project triggers the Prevention of Significant Deterioration (PSD) requirements (326 IAC 2-2). This requires the project to be evaluated as to whether or not it causes both a significant emissions increase and a significant net emissions increase. Determination of the significant emission increase was based on the potential to emit emissions from the IGCC project's emission sources. For the determination of a significant net emission increase, the emission increase consisting of potential emissions from the IGCC project's emission sources minus baseline actual emissions from equipment to be shutdown at the existing Edwardsport Generating Station was determined following the procedures in 326 IAC 2-2-2(d)(4). Based on that evaluation, the Edwardsport IGCC project is subject to 326 IAC 2-2-2 because, pursuant to 326 IAC 2-2-1(xx), the net emissions increase will equal or exceed the significant increase thresholds of one hundred (100) tons per year of carbon monoxide (CO), forty (40) tons per year of volatile organic compounds (VOC), twenty-five (25) tons per year of particulate matter (PM), and fifteen (15) tons per year of $PM_{10}$.

Because the Edwardsport IGCC project will result in a significant net emission increase for emissions of CO, VOC, $PM/PM_{10}/PM_{2.5}$, the proposed project triggers the PSD requirements for these air pollutants as established in 326 IAC 2-2-2 and must meet the following requirements:

- 326 IAC 2-2-3 – "Control Technology Review"
- 326 IAC 2-2-4 – "Air Quality Analysis"
- 326 IAC 2-2-5 – "Air Quality Impact"
- 326 IAC 2-2-6 – "Increment Consumption"
- 326 IAC 2-2-7 – "Additional Analysis"
- 326 IAC 2-2-8(a) – "Source Obligation"
- 326 IAC 2-2-10 – "Source Information"
- 326 IAC 2-2-14 – "Source Impacting Federal Class I Areas"
- 326 IAC 2-2-15 – "Public Participation"

## Proposed New Emission Units

The proposed Integrated Gasification and Combined Cycle (IGCC) electric generating plant will consist of adding the following new emission units:

(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 & GASIF2, permitted in 2008. The gasifiers are not defined as emission units. However, the gasification preheaters designated as GPREHEAT1 and GPREHEAT2 will exhaust through Vent S-5a1 and S-5a2 during startup only.

(2) 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

(3) One natural gas fired 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.

(4) Two (2) natural gas fired gasification pre-heaters 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 Vent S-5a1 and S-5a2, respectively.

(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 & CTHRSG2, permitted in 2008, using diffusion combustors firing either syngas, natural gas, or combined syngas and natural gas, and nitrogen diluent injection when firing syngas, steam injection to control $NO_x$ when firing natural gas, and nitrogen diluent injection and steam injection when co-firing syngas and natural gas, and exhausting to Stacks S-2a and S-2b.

**Table 4: Nominal Heat Input Capacity (HHV)**

| 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 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, using a high-efficiency drift eliminator to control particulate emissions and exhausting to Stack S-9.

(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, 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.

(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.

(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.

## Emission Units to be Retired

The proposed Edwardsport IGCC project will include retiring the following emission units:

(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.

## Enforcement Issues

There are no pending enforcement actions.

## Stack Summary

The following Table 5 summarizes the stacks that correspond to the new emission units operating under normal mode.

**Table 5: Stack Summary**

| **Source ID** | **Stack ID** | **Operation** | **Height** (ft) | **Diameter** (ft) | **Flow Rate** (acfm) | **Temperature** ($^0$F) |
|---|---|---|---|---|---|---|
| GDCBAG | S-1a | Coal Grinding Dust Collector | 45.9 | 3.3 | 29,396 | Ambient |
| COALRECBAG | S-1b | Coal Receiving | 45.9 | 3.3 | 29,396 | Ambient |
| LIMEBAG | S-1c | Lime Silo | 45.9 | 3.3 | 29,396 | Ambient |
| CDPBAG | S-1d | Coal Drop Point | 45.9 | 3.3 | 29,396 | Ambient |
| CTHRSG1 | S-2a | Combustion Turbine/ HRSG #1 | 174.8 | 18.5 | 951,641 | 263.9 |
| CTHRSG2 | S-2b | Combustion Turbine/ HRSG #2 | 174.8 | 18.5 | 951,641 | 263.9 |
| FLR | S-3 | Flare | 198.1 | 4.5 | 156 | 100.1 |
| THRMOX | S-4 | Thermal Oxidizer | 149.9 | 4.0 | 2,251 | 1300 |
| GPREHEAT1<br>GPREHEAT2 | S-5a1<br>S-5a2 | Gasification Pre-Heaters 1 and 2 | 290.0 | 0.8 | 4,882 | 199.1 |
| TPREHEAT1<br>TPREHEAT2 | S-5b1<br>S-5b2 | Turbine Pre-Heaters 1 and 2 | 15.1 | 0.8 | 1,758 | 299.9 |
| AUXBLR | S-6 | Auxiliary Boiler | 75.1 | 6.0 | 105,754 | 499.7 |
| EMDSL | S-7 | Emergency Diesel Generator | 14.0 | 1.1 | 10,384 | 800.3 |
| FIRPMP | S-8 | Fire Water Pump | 12.0 | 0.3 | 2,061 | 789.5 |
| CT1 – CT22 | S-9 | Cooling Tower Cells 1-22 | 61.0 | 32.8 | 1,163,431 | 94.7 |

## Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

## Permit Level Determination – Part 70

Pursuant to 326 IAC 2-7-1(29), Potential to Emit is defined as “the maximum capacity of a stationary source 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,.”

Tables 6 and 7 below are 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.

The proposed plant will have two modes of operation: normal and startup/shutdown. The emission estimates provided in Tables 6 and 7 reflect the maximum emissions from the two operating modes. Refer to Appendix A for backup emission calculations for the two modes.

**Table 6: IGCC Plant - PTE Before Controls of the Modification**

| Pollutant | Normal Operation – PTE (ton/yr) |
|---|---|
| CO | 917.2 |
| $NO_X$ | 2,121.5 |
| PM | 6,980.9 |
| $PM_{10}$ | 6,940.1 |
| $PM_{2.5}$ | 6,925.5 |
| $SO_2$ | 358.5 |
| VOC | 35.9 |
| Lead | 0.037 |
| $H_2SO_4$ | 56.06 |
| Beryllium | 0.00163 |
| Mercury | 0.00383 |
| Fluorides | 0.0 |

**Table 7: IGCC Plant – HAP PTE Before Controls of the Modification**

| Pollutant | Normal Operation – PTE (ton/yr) |
|---|---|
| Acetaldehyde | 0.74 |
| Acrolein | 0.12 |
| Formaldehyde | 5.94 |
| Mercury | 0.004 |
| Hexane | 1.41 |
| Toluene | 2.40 |
| Xylene | 1.18 |
| Ethyl Benzene | 0.59 |
| Benzene | 0.22 |
| TOTAL | 12.57 |

This source modification is subject to 326 IAC 2-7-10.5(f) and (g), pursuant to 326 IAC 2-7-10.5(f)(1) and (f)(4), because the proposed IGCC project resulted in a significant net emission increase for carbon monoxide (CO), particulate matter (PM), and volatile organic compounds (VOC), as well as the potential to emit nitrogen oxides ($NO_x$) and sulfur dioxide ($SO_2$) emissions being greater than twenty-five (25) tons per year before control. 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 the modification requires significant changes in existing Part 70 permit terms and conditions.

**Permit Level Determination – PSD or Emission Offset**

Tables 8 and 9 below summarize 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 Source Modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit. Table 8 presents the net change in emissions associated with the IGCC project based on continuous operation with syngas combustion in the CTs (referred to as the “normal operating mode”) without periods of startup or shutdown. Table 9 presents the net change in emissions from the IGCC project taking into account normal operations, again with syngas combustion in the CTs, and startup/shutdown periods (referred to as the “normal/startup/shutdown/trip operating mode). Tables 8 and 9 represent opposite extremes of operational mode for the IGCC facility, ranging from continuous normal mode operation with no start-up events in an annual period (Table 8) to the maximum number of start-ups (76 annual events) projected by Duke Energy with normal mode operating hours correspondingly reduced (Table 9). Any other intermediate scenario involving a number of start-ups between 0 and 76 will result in potential to emit values for each pollutant at a commensurate level between the values depicted on Tables 8 and 9. The net change in emissions from Tables 8 and 9 were used in determining initial PSD applicability. From these Tables, it can be concluded that a significant increase in net emissions is projected from the IGCC project for CO, $PM/PM_{10}/PM_{2.5}$, and VOC.

**Table 8: Potential to Emit[1] (ton/yr)**

**IGCC Plant – Normal Operating Mode**

| Process / Emission Unit | CO | $NO_X$ | PM | $PM_{10}$/ $PM_{2.5}$ | $SO_2$ | VOC | $H_2SO_4$ | Lead | Beryllium | Mercury | Fluorides |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Two Combustion Turbines on Syngas | 832.2 | 1989.0 | 342.5 | 342.5 | 254.0 | 29.9 | 56.06 | 0.037 | 1.62E-02 | 3.6E-03 | - |
| Pre-Heaters Turbine Gas Conditioning | 4.4 | 7.3 | 0.3 | 0.3 | 0.03 | 1.7 | - | - | - | - | - |
| Flare Pilot Normal Operation | 0.96 | 1.2 | 0.1 | 0.1 | 0.007 | 0.06 | - | - | - | - | - |
| Thermal Oxidizer Normal Operation | 1.4 | 1.7 | 0.1 | 0.1 | 87.0 | 0.1 | - | - | - | - | - |
| Aux Boiler | 61.8 | 102.9 | 5.6 | 5.6 | 0.6 | 4.0 | - | - | 9.00E-06 | 1.95E-04 | - |
| Emergency Generator | 3.0 | 7.2 | 0.1 | 0.1 | 0.2 | 0.4 | - | - | - | - | - |
| Emergency Fire Pump | 0.7 | 3.3 | 0.2 | 0.2 | 0.2 | 0.3 | - | - | - | - | - |
| Cooling Tower | - | - | 28.0 | 28.0 | - | 0.0 | - | - | - | - | - |
| Material Handling Baghouses | - | - | 6.0 | 6.0 | - | - | - | - | - | - | - |
| Fugitive Emissions | - | - | 30.1 | 11.52 | - | - | - | - | - | - | - |
| Equipment Trips/Malfunctions | 13.1 | 9.0 | 4.1 | 4.1 | 16.5 | 0.4 | - | - | | | - |
| Total for Modification | 917.5 | 2121.5 | 417.2 | 397.1 | 358.5 | 36.8 | 56.1 | 0.037 | 1.6E-02 | 3.6E-03 | 0 |
| Contemporaneous Increase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Contemporaneous Decrease | 69.5 | 2,384.0 | 207.4 | 47.7 | 10,299.1 | 8.3 | 515.0 | 0.0575 | 2.90E-03 | 0.0114 | 20.67 |
| Total for Modification after Netting | 848.0 | -262.5 | 209.6 | 349.4 | -9940.6 | 28.5 | -458.9 | -0.021 | -1.0E-03 | -8.0E-03 | -20.67 |
| PSD Major Source Threshold | 100 | 100 | 100 | 100 | 100 | 100 | 100 | NA | NA | NA | NA |
| PSD Significant Emission Level | 100 | 40 | 25 | 15 | 40 | 40 | 7 | 0.6 | 0.0004 | 0.1 | 3 |

[1]PTE Emission estimates for the combustion turbines reflect the maximum based on the fuel being combusted. Emissions of CO, NOx and VOC are based on worst case syngas and natural gas. PM and $H_2SO_4$ emissions are based on 100% syngas.

**Table 9: Potential to Emit[1] (ton/yr)**

**IGCC Plant –Startup/Shutdown/Trip Operating Mode**

| Process / Emission Unit | CO | $NO_X$ | PM | $PM_{10}$/ $PM_{2.5}$ | $SO_2$ | VOC | $H_2SO_4$ | Lead | Beryllium | Mercury | Fluorides |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Natural Gas Fired Gasification Pre-Heaters | 5.5 | 6.5 | 0.5 | 0.5 | 0.04 | 0.3 | - | - | - | - | - |
| Pre-Heaters Turbine Gas Conditioning | 4.4 | 7.27 | 0.33 | 0.33 | 0.026 | 1.7 | - | - | - | - | - |
| Startup and Shutdown Emissions[2] | 373.1 | 261.3 | 20.0 | 20.0 | 105.7 | 53.4 | 0.2 | 0.037 | 1.62E-03 | 3.6E-03 | |
| Aux Boiler | 61.8 | 102.9 | 5.6 | 5.6 | 0.6 | 4.0 | | | - | - | |
| Emergency Generator | 3.0 | 7.2 | 0.1 | 0.1 | 0.2 | 0.4 | - | - | - | - | - |
| Emergency Fire Pump | 0.7 | 3.3 | 0.2 | 0.2 | 0.2 | 0.3 | - | - | - | - | - |
| Cooling Tower | - | - | 28.0 | 28.0 | - | 0.0 | - | - | - | - | - |
| Material Handling Baghouses | - | - | 6.0 | 6.0 | - | - | - | - | - | - | - |
| Fugitive Emissions | - | - | 30.1 | 11.52 | - | - | - | - | - | - | - |
| Equipment Trips/Malfunctions | 13.1 | 9.0 | 4.1 | 4.1 | 16.5 | 0.4 | - | - | - | - | - |
| Total for Modification | 461.6 | 397.5 | 95.0 | 81.0 | 123.2 | 60.5 | 0.2 | 0.037 | 1.6E-03 | 3.6E-03 | 0 |
| Contemporaneous Increase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Contemporaneous Decrease | 69.5 | 2384.0 | 207.4 | 47.7 | 10,299.1 | 8.3 | 515.0 | 0.0575 | 2.90E-03 | 0.0114 | 20.67 |
| Total for Modification after Netting | 392.1 | -1987.0 | -112.4 | 33.3 | -10166.9 | 52.2 | -514.8 | -0.0207 | -1.27E-03 | -7.84E-03 | -20.7 |
| PSD Major Source Threshold | 100 | 100 | 100 | 100 | 100 | 100 | 100 | NA | NA | NA | NA |
| PSD Significant Emission Level | 100 | 40 | 25 | 15 | 40 | 40 | 7 | 0.6 | 0.0004 | 0.1 | 3 |

[1] PTE Emission estimates for the combustion turbines reflect the maximum based on the fuel being combusted. Emissions of CO, NOx and VOC are based on worst case syngas and natural gas. PM and H2SO4 emissions are based on 100% syngas.
[2] The number of startups and shutdowns was based on a worst-case assumption of 76 per year.

The Permittee has provided information as part of the application for this approval that, based on Actual to Potential test in (326 IAC 2-2-2(d)(4)), this modification at a major stationary source will be major for Prevention of Significant Deterioration under 326 IAC 2-2-1. After consideration of all control measures, potential emissions of CO, PM, $PM_{10}$, $PM_{2.5}$ and VOC are greater than the PSD significant levels.

## Permit Level Determination

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of one or more regulated pollutants are equal to or greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

(b) Fugitive Emissions
Since this type of operation is one of the twenty-eight (28) listed source categories under 326 IAC 2-2 and since there are applicable New Source Performance Standards that were in effect on August 7, 1980, the fugitive emissions are counted toward determination of PSD applicability.

## Source Status Determination

(a) PSD Major Source
Duke Energy Indiana – Edwardsport Generating Station is classified as an existing major stationary source under the PSD program because one or more attainment regulated pollutants are emitted at a rate of 100 tons per year or more.

(b) 1 of 28 Listed Source Categories
Duke Energy Indiana – Edwardsport Generating Station operations are clasified in one of the 28 listed source categories under 326 IAC 2-2-1(gg).

(c) Part 70 Source
Duke Energy Indiana – Edwardsport Generating Station is a Part 70 source because one or more attainment regulated pollutants are emitted at a rate of 100 tons per year. Edwardsport Generating Station will no longer be a major HAP source after retirement of the existing units and prior to commencement of operation of the IGCC units,

## Federal Rule Applicability Determination

The following federal rules are applicable to the source due to this modification:

(a) New Source Performance Standards (NSPS) (326 IAC 12 and 40 CFR Part 60):

(1) 40 CFR 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, that is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr)) heat input of fossil fuel (either alone or in combination with any other fuel).

326 IAC 12, 40 CFR 60, Subpart Da is applicable to the following:

- Name: Two combined cycle combustion turbines
- Emission Source ID: CTHRSG1 and CTHRSG2
- Fuel combusted: Coal-derived syngas and natural gas
- Construction Date: After February 28, 2005.

Nonapplicable portions of the NSPS will not be included in the permit. The combustion turbines are subject to the following portions of Subpart Da.

- 40 CFR 60.40Da
- 40 CFR 60.41Da
- 40 CFR 60.42Da(c)(1),(2)
- 40 CFR 60.43Da (i)(1)(i) and (ii)
- 40 CFR 60 44Da(f)(1)
- 40 CFR 60.45Da(b)
- 40 CFR 60.48Da
- 40 CFR 60.49Da
- 40 CFR 60.50Da
- 40 CFR 60.51Da
- 40 CFR 60.52Da

(2) 40 CFR 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units 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)).

326 IAC 12, 40 CFR 60, Subpart Db is applicable to the following units:

- Name: Auxiliary Boiler (300 MMBtu/hr)
- Emission Source ID: AUXBLR
- Fuel Combusted: Natural Gas

Nonapplicable portions of the NSPS will not be included in the permit. The auxiliary boiler is subject to the following portions of Subpart Db.

- 40 CFR 60.40b
- 40 CFR 60.41b
- 40 CFR 60.42b(k)(2)
- 40 CFR 60.44b(a)(1)
- 40 CFR 60.44b(h)(j)
- 40 CFR 60.46b(c),(e),(g),(h)
- 40 CFR 60.48b(b),(e)(2)(i)
- 40 CFR 60.49b(a),(b),(d),(g),(h),(i),(o),(p),(q)

(3) 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:

- Name: Coal Preparation Plants
- Emission Source ID: Coal Receiving, Transferring, Storage and Processing

Nonapplicable portions of the NSPS will not be included in the permit. 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)

(4) 40 CFR 60, Subpart HHHH - Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units, Hg Budget Trading Program General Provisions (326 IAC 24-4 has been adopted for state implementation of the Hg Budget Trading Program but is not yet effective.)

326 IAC 12, 40 CFR 60, Subpart HHHH is applicable to the following units:

- Name: stationary combustion turbines while burning coal or coal derived fuel, alone or in combination with natural gas.
- Emission Source ID: CTHRSG1 and CTHRSG2

Nonapplicable portions of the NSPS will not be included in the permit. The combustion turbines are subject to the following portions of Subpart HHHH while burning coal or coal-derived fuel, alone or in combination with natural gas

- 40 CFR 60.4101
- 40 CFR 60.4102
- 40 CFR 60.4104(a)(1)
- 40 CFR 60.4106
- 40 CFR 60.4107
- 40 CFR 60.4110
- 40 CFR 60.4111
- 40 CFR 60.4112
- 40 CFR 60.4113
- 40 CFR 60.4120
- 40 CFR 60.4121
- 40 CFR 60.4122
- 40 CFR 60.4123
- 40 CFR 60.4124
- 40 CFR 60.4152
- 40 CFR 60.4154
- 40 CFR 60.4155
- 40 CFR 60.4157
- 40 CFR 60.4160
- 40 CFR 60.4170
- 40 CFR 60.4171
- 40 CFR 60.4172
- 40 CFR 60.4173
- 40 CFR 60.4174
- 40 CFR 60.4175
- 40 CFR 60.4176

(5) 40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

(A) 326 IAC 12, 40 CFR 60 Subpart IIII is applicable to the following units:

- Name: One 2200 BHP Emergency Generator which will commence construction after July 11, 2005 and will be manufacture after April 1, 2006.
- Emission Source ID: EMDSL
- Fuel Combusted: Low sulfur distillate fuel oil

Nonapplicable portions of the NSPS will not be included in the permit. The emergency generator is subject to the following portions of Subpart IIII.

- 40 CFR 60.4200(a)(2)(i)
- 40 CFR 60.4205(b)

- 40 CFR 60.4206
- 40 CFR 60.4207(a), (b)
- 40 CFR 60.4209(a)
- 40 CFR 60.4211(a), (e)
- 40 CFR 60.4212
- 40 CFR 60.4214(b)
- 40 CFR 60.4218
- 40 CFR 60.4219

(B) 326 IAC 12, 40 CFR 60 Subpart IIII is applicable to the following units:

- Name: One 420 BHP Emergency Fire Pump which will commence construction after July 11, 2005 and will be manufacture after April 1, 2006
- Emission Source ID: FIRPMP
- Fuel Combusted: Low sulfur distillate fuel oil

Nonapplicable portions of the NSPS will not be included in the permit. The emergency fire pump is subject to the following portions of Subpart IIII.

- 40 CFR 60.4200(a)(2)(ii)
- 40 CFR 60.4205(c)
- 40 CFR 60.4206
- 40 CFR 60.4207(a), (b)
- 40 CFR 60.4209(a)
- 40 CFR 60.4211(c)
- 40 CFR 60.4212
- 40 CFR 60.4214(b)
- 40 CFR 60.4218
- 40 CFR 60.4219

(6) 40 CFR 60, Subpart OOO - Standards of Performance for Nonmetallic Mineral Processing Plants - 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.

326 IAC 12, 40 CFR 60, Subpart OOO is applicable to the following units:

- Name: Lime Silo
- Emission Point ID: LIMEBAG

Nonapplicable portions of the NSPS will not be included in the permit. The lime silo is subject to the following portions of Subpart OOO.

- 40 CFR 60.670
- 40 CFR 60.671
- 40 CFR 60.672(f)
- 40 CFR 60.673
- 40 CFR 60.675(a), (c)(2)
- 40 CFR 60.676(f), (i)(1), (j)

(b) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC20 and 40 CFR Part 63) applicable to this proposed modification. After permanent shutdown of the existing electrical generating equipment at the Edwardsport Electrical Generating Station (which will occur prior to start-up of the new IGCC facilities), the station (source) will be classified as a minor stationary source of regulated Federal Hazardous Air Pollutants.

(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 requirements of 40 CFR Part 64, CAM, are not applicable to the following processes/emission units because proposed modification will not add any additional control devices for these processes/emission units:

- Truck Traffic on Paved Roads
- Dropping of Coal from Conveyor onto Piles
- Loading of Slag onto Storage Piles
- Equipment Traffic on Coal Piles
- Wind Erosion on Coal Piles
- Wind Erosion on Slag Piles
- Natural Gas Fired Gasification Pre-Heater
- Natural Gas Fired Pre-Heaters - Turbine Gas Conditioning
- Auxiliary Natural Gas Fired Boiler
- Diesel Fired Emergency Generator
- Diesel Fired Emergency Fire Pump

Table 10 below is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to each new emission unit involved with the proposed IGCC plant:

**Table 10: CAM Applicability Analysis - PM / $PM_{10}$ / $PM_{2.5}$ and VOC**

| Emission Unit | Control Device Used | Emission Limitation (Y/N) | Uncontrolled PTE (ton/yr) | Controlled PTE (ton/yr) | Major Source Threshold (ton/yr) | CAM Applicable (Y/N) | Large Unit (Y/N) |
|---|---|---|---|---|---|---|---|
| Coal Processing Gasifiers | Baghouse | Y | PM: 1500 | PM: 1.5 | 100 | Y | N |
| Coal Receiving | Baghouse | Y | PM: 1500 | PM: 1.5 | 100 | Y | N |
| Lime Silo | Baghouse | Y | PM: 1500 | PM: 1.5 | 100 | Y | N |
| Coal Pile Transfer Point | Baghouse | Y | PM: 1500 | PM: 1.5 | 100 | Y | N |
| Combustion Turbines - Syngas | N Diluent | N | Not Applicable | Not Applicable | 100 | N* | N |
| Combustion Turbines - Natural Gas | Steam Injection | N | Not Applicable | Not Applicable | 100 | N* | N |
| Cooling Tower | Drift Eliminator | N | Not Applicable | Not Applicable | 100 | N** | N |
| Low Temp Gas Cooling and Acid Gas Removal | Flare | Y | VOC: 9.5 | VOC: 0.19 | 100 | N | N |
| Acid Gas Removal to Sulfur Recovery Unit | Thermal Oxidizer | Y | | | 100 | N | N |
| Acid Gas Removal to Gas Recycle | Thermal Oxidizer | Y | | | 100 | N | N |
| Sulfur Recovery Unit | Thermal Oxidizer | Y | VOC: 26 | VOC: 0.52 | 100 | N | N |
| Sulfur Recovery Unit to Tail Gas Unit | Thermal Oxidizer | Y | | | 100 | N | N |
| Tail Gas Unit to Gas Recycle | Thermal Oxidizer | Y | | | 100 | N | N |
| Fines Handling to Sulfur Recovery Unit | Thermal Oxidizer | Y | | | 100 | N | N |

* Although the turbines are equipped with steam injection and N diluent to reduce $NO_X$ emission, since the applicable NSPS provisions, 40 CFR 60, Subpart Da specify a continuous monitoring method for $NO_X$, the turbines are not subject to the CAM requirements as allowed by 40 CFR 64.2(b)(i).

** Drift eliminators are not considered control devices as defined in 40 CFR 64.1 since the drift eliminators act as passive control devices.

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are applicable to:

- Coal Processing Gasifiers,
- Coal Receiving,
- Lime Silo, and
- Coal Pile Drop Point

for PM emissions upon issuance of the Title V Renewal.

Since none of these are large emission units, a CAM plan must be submitted as part of the Renewal application for a Part 70 permit for the Edwardsport Generating Station. The expiration date of the station's Part 70 permit is August 10, 2009.

(d) Acid Rain Program (326 IAC 21, 40 CFR 72 through 40 CFR 78).

The IGCC's combined cycle combustion turbines 1 and 2 (CTHRSG 1 and CTHRSG2, Stack S-2a and S-2b), will be affected units under the federal Acid Rain Program under 40 CFR 72.6(a)(3)(i).

Pursuant to 40 CFR 72.9, the affected units must:

(1) Submit a complete Acid Rain permit application (including a compliance plan) as specified in Sec. 72.30;

(2) Submit a complete reduced utilization plan if required under Sec. 72.43; and

(3) Submit any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit.

In addition, the affected units must comply with the monitoring requirements as provided in 40 CFR 75. The emissions measurements recorded and reported in accordance with 40 CFR 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

## State Rule Applicability Determination – Source Wide

The following state rules are applicable to the source due to the modification:

**326 IAC 2-2 and 2-3 (PSD and Emission Offset)**
PSD and Emission Offset applicability is discussed under the Permit Level Determination – PSD and Emission Offset section.

**326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))**
The operation of the proposed IGCC plant at Duke Energy Indiana - Edwardsport Generating Station will emit less than ten (10) tons per year for a single HAP and less than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply.

**326 IAC 2-7-10.5 (Part 70 Permits; Source Modifications)**
Pursuant to 326 IAC 2-7-10.5(f), the source modification are subject to the requirements of 326 IAC 2-7-10.5(g).

**326 IAC 2-7-12 Permit Modification**
Pursuant to 326 IAC 2-7-12(d), the IGCC project triggers the requirement for a significant modification to the Part 70 permit because the modification requires significant changes in existing Part 70 permit terms and conditions.

**326 IAC 2-6 (Emission Reporting)**
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. 326 IAC 2-6-4(c) and shall meet the following requirements:

(1) Indicate estimated actual emissions of all pollutants listed in 326IAC 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 purposes of Part 70 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, P.O. Box 6015
Indianapolis, Indiana 46206-6015

**326 IAC 5-1 (Opacity Limitation)**
Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-3-1 (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 non-overlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

## State Rule Applicability Determination – Source Wide

**326 IAC 3-5-1 (Applicability; monitoring requirements for applicable pollutants)**
Pursuant to 326 IAC 3-5-1(a)(2)(b), this rule applies to any facility required to perform continuous monitoring under 326 IAC 12, which incorporates by reference the requirements of 40 CFR 60, or by a standard for hazardous air pollutants under 326 IAC 14, which incorporates by reference the requirements of 40 CFR 61, or 326 IAC 20, which incorporates by reference the requirements of 40 CFR 63.

Table 11 presents the emission units that are subject to 40 CFR 60 and their monitoring requirements:

**Table 11: IGCC Plant Monitoring Applicability**

| Equipment Description | NSPS | Limitations | Monitoring Required |
|---|---|---|---|
| Combustion Turbines/ HRSGs - Combusting Syngas and Natural Gas | Da | ▪ $SO_2$ – 1.4 lb/MWH, 30-day rolling<br>▪ $NO_x$ - 1.0 lb/MWH, 30-day rolling<br>▪ Hg – 20E-06 lb/MWH, 12-month rolling<br>▪ PM – 0.14 lb/MWH, 0.015 lb/MMBtu<br>▪ Opacity <20% | ▪ CEM<br>▪ CEM<br>▪ 40 CFR Part 60, Subpart Da<br>▪ CEM (gross output limit)<br>▪ COM |
| Combustion Turbines/ HRSGs - Combusting Syngas and Natural Gas | HHHH | ▪ Requirements for Hg Trading | ▪ 40 CFR Part 60, Subpart Da |
| Auxiliary Boiler (300 MMBtu/hr, NG fired) | Db >100 MMBtu/hr | $NO_x$ - 0.1 lb/MMBtu LHRR<br>- 0.2 lb/MMBtu HHRR<br>3-hr average | CEM |
| Coal Processing and Conveying Equipment (>200 tons/day) | Y | 20% Opacity | NA |
| Lime Conveying and Storage | OOO | PM – 0.022 gr/dscf<br>Opacity <7% | NA |
| Emergency Generator<br>Emergency Fire Pump | IIII | NonRoad IC Engines – 60.4202<br>Table 4 to Subpart IIII | Non-resettable hour meter |

**326 IAC 5-1 (Opacity Limitation)**
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 non-overlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

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

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

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

Natural Gas Fired Auxiliary Boiler (AUXBLR, Stack S-6)
Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(d)), the PM emissions from the auxiliary boiler stack shall not exceed 0.2474 pound per million Btu heat input (lb/MMBtu). This limitation was calculated using the following equation:

Particulate emissions from indirect heating facilities constructed after September 21, 1983 shall be limited by the following equation:

$$Pt = 1.09/Q^{0.26}$$
$$= 1.09/(300)^{0.26}$$
$$= 0.2474$$

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) heat input. The maximum operating capacity rating is defined as the maximum capacity at which the facility is operated or the nameplate capacity, whichever is specified in the facility's permit application, except when some lower capacity is contained in the facility's operation permit; in which case, the capacity specified in the operation permit shall be used.

Material Handling Baghouses (GDCBAG, COALRECBAG, LIMEBAG AND CDPBAG, Stack ID: S-1b, S-1c and S-1d)
Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the material handling baghouses shall not exceed the following:

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

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

OR

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

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

The baghouses shall be in operation at all times the material handling processes are in operation, in order to comply with this limit.

**Table 12: Summary of Process Weight Rate Limits**

| **Process / Emission Unit** | **P** (ton/hr) | **E** (lb/hr) | **Equation Used** |
|---|---|---|---|
| Coal Receiving | 1200 | 80 | (b) |
| Lime Silo | 300 | 63 | (b) |
| Coal Drop Point | 250 | 61 | (b) |
| Coal Gasification Preparation | 250 | 61 | (b) |

**326 IAC 7-1.1-2 (Sulfur dioxide emission limitations)**

The sulfur dioxide emission limitations in 326 IAC 7-1.1-2 are not applicable because a permit under 326 IAC 2 is being issued for this modification.

**326 IAC 8-1-6 (New facilities; general reduction requirements)**

Compliance with the VOC emission limitations established pursuant to 326 IAC 2-2 satisfies the VOC BACT requirements under 326 IAC 8-1-6.

**326 IAC 10-4 (Nitrogen Oxides Budget Trading Program)**

None of the emission units associated with the Edwardsport IGCC Project will be $NO_x$ budget units under 326 IAC 10-4 since the $NO_x$ budget program will sunset after the 2008 control period. See 326 IAC 10-4-16. The IGCC units will not be operational until 2011 or later control periods and will be subject instead to the CAIR $NO_x$ Ozone Trading Program, 326 IAC 24-3.

**326 IAC 24-1 (Clean Air Interstate $NO_X$ Annual Trading Program)**

Pursuant to 326 IAC 24-1-1(a)(1), each of Combined Cycle Combustion Turbines at this source (CTHRSG1 and CTHRSG2, Stack S-2a and S-2b) will be a CAIR $NO_x$ unit and will be subject to the CAIR $NO_x$ annual trading program because start-up of it's combustion chamber will have occurred after November 15, 1990 and it will serve an electrical generator that has a nameplate capacity greater than twenty-five (25) megawatts and produces electricity for sale.

Because this source meets the criteria of having one (1) or more CAIR NOx units, it is a CAIR NOx source. The Permittee shall be subject to the requirements of 326 IAC 24-1 ($NO_x$ Annual Trading Program).

**326 IAC 24-2 ($SO_2$ Trading Program)**

Pursuant to 326 IAC 24-2-1(a), each of Combined Cycle Combustion Turbines at this source (CTHRSG1 and CTHRSG2, Stack S-2a and S-2b) will be a CAIR $SO_2$ unit and will be subject to the CAIR $SO_2$ trading program

**326 IAC-24-3 ($NO_X$ Ozone Season Trading Program)**

Pursuant to 326 IAC 24-3-1(a), each of Combined Cycle Combustion Turbines at this source (CTHRSG1 and CTHRSG2, Stack S-2a and S-2b) will be a CAIR $SO_2$ unit and will be subject to the CAIR $SO_2$ trading program.

Pursuant to 326 IAC 24-3-2(49)(A)(iii), the Auxiliary Boiler (AUXBLR, Stack S-6) will be a “Large Affected Unit” because it will have commenced operation on or after January 1, 1999, is a unit with a maximum design heat input greater than two hundred fifty million (250,000,000) Btus per hour that:

(AA) at no time serves a generator producing electricity for sale; or

(BB) at any time serves a generator producing electricity for sale, if any such generator has a nameplate capacity of twenty-five (25) megawatts or less and has the potential to use no more than fifty percent (50%) of the potential electrical output capacity of the unit.

Pursuant to 326 IAC 24-3-1(a)(2), a “Large Affected Unit” is a $NO_X$ ozone season unit. Because this source meets the criteria of having one (1) or more $NO_X$ ozone season units, it will be/is a $NO_X$ ozone season source. The Permittee shall be subject to the requirements of 326 IAC 24-3 (CAIR $NO_X$ Ozone Season Trading Program).

## 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.

Changes to the compliance determination and monitoring requirements are detailed in Appendix D - Proposed Changes to Part 70 Operating Permit.

The Compliance Determination Requirements applicable to this modification are as follows:

(a) Table 13 summarizes the emission units subject to compliance testing requirements.

**Table 13: Summary of Compliance Testing Requirements**

| Emission Unit | Control Device | Timeframe for Testing | Pollutant | Frequency of Testing | Limit or Requirement |
|---|---|---|---|---|---|
| Combustion Turbines/HRSGs 1 and 2 | Nitrogen diluent injection for $NO_x$ control when combusting syngas<br><br>Steam injection for NOx control when combusting natural gas | 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 such facility | ● $SO_2$<br>● $NO_x$<br>● Hg<br>● PM<br>● Opacity | Once every 5 years | ● 1.4 lbs/MWH<br>● 1.0 lb/MWH<br>● 20E-06 lb/MWH<br>● 0.14 lb/MWH<br>● 20% |
| Gasification Pre-Heaters 1 and 2 | None | None | None | None | Tons per Year |
| Turbine Gas Conditioning Pre-Heaters 1 and 2 | None | None | None | None | Tons per Year |

**Table 13: Summary of Compliance Testing Requirements**

| Emission Unit | Control Device | Timeframe for Testing | Pollutant | Frequency of Testing | Limit or Requirement |
|---|---|---|---|---|---|
| Flare Pilot (elevated open flare) | None | Within 10 days of initial startup of any unit in the gasification block, conduct tests of the flare to confirm compliance with 40 CFR 60.18 | None | Initially as defined in 40 CFR 60.18 (currently no feasible methods for emission monitoring) | lbs/MMBtu gasification input |
| Thermal Oxidizer | None | 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 such facility | $SO_2$ | Once every 5 years | lbs/MMBtu gasification input |
| Auxiliary Boiler | None | 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 such facility | $NO_x$ | Once every 5 years | 0.2 lbs/MMBtu high heat release rate |
| Emergency Generator | None | None | None | None | NSPS Subpart IIII |
| Emergency Fire Pump | None | None | None | None | NSPS Subpart IIII |
| Cooling Tower | Drift Eliminator | None | None | None | Tons per Year |
| Coal/Lime Material Handling Baghouses | Baghouse | 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 such facility. | PM | Once every 5 years | 0.003 grains/dscf |

**Table 13: Summary of Compliance Testing Requirements**

| Emission Unit | Control Device | Timeframe for Testing | Pollutant | Frequency of Testing | Limit or Requirement |
|---|---|---|---|---|---|
| Fugitive Emissions (Coal/Slag Piles and Paved Roads) | None (Control Techniques) | None | None | None | Tons per Year |

(b) Table 14 summarizes the applicable compliance monitoring requirements.

**Table 14: IGCC Plant Monitoring Applicability**

| Equipment Description | NSPS | Limitations | Monitoring Required |
|---|---|---|---|
| Combustion Turbines - Combusting Syngas and Natural Gas | Da | ▪ $SO_2$ – 1.4 lb/MWH, 30-day rolling<br>▪ $NO_x$ - 1.0 lb/MWH, 30-day rolling<br>▪ Hg – 20E-06 lb/MWH, 12-month rolling<br>▪ PM – 0.14 lb/MWH, 0.015 lb/MMBtu<br>▪ Opacity <20% | ▪ CEM<br>▪ CEM<br>▪ 40 CFR Part 60, Subpart Da<br>▪ CEM (gross output limit)<br>▪ COM |
| Combustion Turbines - Combusting Syngas and Natural Gas | HHHH | ▪ Requirements for Hg Trading | ▪ 40 CFR Part 60, Subpart Da |
| Auxiliary Boiler (300 MMBtu/hr, NG fired) | Db >100 MMBtu/hr | $NO_x$ – 0.1 lb/MMBtu LHRR<br>- 0.2 lb/MMBtu HHRR<br>3-hr average | CEM |
| Coal Processing and Conveying Equipment (>200 tons/day) | Y | 20% Opacity | NA |
| Lime Conveying and Storage | OOO | PM – 0.022 gr/dscf<br>Opacity <7% | NA |
| ▪ Emergency Generator<br>▪ Emergency Fire Pump | IIII | ▪ Emission standards for new nonroad CI engines in §60.4202<br>▪ Table 4 to Subpart IIII | Non-resettable hour meter |

**Air Quality Impact Analysis Summary**

Based on the potential emissions after controls, a Prevention of Significant Deterioration (PSD) air quality analysis was triggered for CO, particulate emissions ($PM/PM_{10}/PM_{2.5}$) and VOC. The significant impact analysis determined that modeling concentrations for CO, particulate emissions ($PM/PM_{10}/PM_{2.5}$) and VOC did not exceed the significant impact levels. A refined analysis, PSD increment analysis and National Ambient Air Quality Standards (NAAQS) analysis, was not required. The pre- and post-construction monitoring requirements were not triggered as a result of this analysis. An additional impact analysis for Hazardous Air Pollutant (HAP) was conducted and showed no significant impact. Based on the modeling results, the proposed modification will not have a significant impact upon federal air quality standards.

See Appendix C of this Technical Support Document for the detailed Air Quality Impact Analysis.

## Endangered Species

The Clean Air Act (CAA) does not contain an express requirement for the applicant or the permitting agency to analyze or consider the impact of hazardous air pollutants on endangered species when applying for or making a decision on a PSD permit. The CAA only requires impacts to endangered species be considered when the US EPA modifies the HAPs list or promulgates a NESHAP. (42 USC 7412).

In addition, Indiana's state rules do not require the performance of studies or analyses to determine the effect of toxic emissions from a source on federal or state-listed endangered species in the PSD permitting process.

Endangered species are protected under state and federal laws, which prohibit the unlawful taking of an endangered species. IC 14-22-34 and 16 USC 701 et. seq. Below is a listing of endangered, threatened or rare species in Indiana.

**Table 15: Endangered, Threatened or Rare Species – Knox County, Indiana**

| Species Name | Common Name | Type | Federal | State |
|---|---|---|---|---|
| Cyprogenia stegaria | Eastern Fanshell Pearlymussel | Mollusk | LE | SE |
| Epioblasma flexuosa | Leafshell | Mollusk | | SX |
| Epioblasma propinqua | Tennessee Riffleshell | Mollusk | | SX |
| Epioblasma torulosa rangiana | Northern Riffleshell | Mollusk | LE | SE |
| Epioblasma torulosa torulosa | Tubercled Blossom | Mollusk | LE | SE |
| Epioblasma triquetra | Snuffbox | Mollusk | | SE |
| Fusconaia subrotunda | Longsolid | Mollusk | | SE |
| Hemistena lata | Cracking Pearlymussel | Mollusk | LE | SX |
| Obovaria retusa | Ring Pink | Mollusk | LE | SX |
| Obovaria subrotunda | Round Hickorynut | Mollusk | | SSC |
| Plethobasus cicatricosus | White Wartyback | Mollusk | LE | SE |
| Plethobasus cyphyus | Sheepnose | Mollusk | C | SE |
| Pleurobema clava | Clubshell | Mollusk | LE | SE |
| Pleurobema cordatum | Ohio Pigtoe | Mollusk | | SSC |
| Pleurobema plenum | Rough Pigtoe | Mollusk | LE | SE |
| Pleurobema pyramidatum | Pyramid Pigtoe | Mollusk | | SE |
| Potamilus capax | Fat Pocketbook | Mollusk | LE | SE |
| Ptychobranchus fasciolaris | Kidneyshell | Mollusk | | SSC |
| Quadrula cylindrica cylindrica | Rabbitsfoot | Mollusk | | SE |
| Nicrophorus americanus | American Burying Beetle | Insect | LE | SX |
| Homoeoneuria ammophila | A Sand-filtering Mayfly | Insect | | SE |
| Siphloplecton interlineatum | A Sand Minnow Mayfly | Insect | | SE |
| Ammocrypta clara | Western Sand Darter | Fish | | SSC |

**Table 15: Endangered, Threatened or Rare Species – Knox County, Indiana**

| Species Name | Common Name | Type | Federal | State |
|---|---|---|---|---|
| Percina evides | Gilt Darter | Fish | | SE |
| Percina uranidea | Stargazing Darter | Fish | | SX |
| Cryptobranchus alleganiensis alleganiensis | Hellbender | Amphibian | | SE |
| Farancia abacura reinwardtii | Western Mud Snake | Reptile | | SX |
| Kinosternon subrubrum | Eastern Mud Turtle | Reptile | | SE |
| Liochlorophis vernalis | Smooth Green Snake | Reptile | | SE |
| Nerodia erythrogaster neglecta | Copperbelly Water Snake | Reptile | PS:LT | SE |
| Pseudemys concinna hieroglyphica | Hieroglyphic River Cooter | Reptile | | SE |
| Asio flammeus | Short-eared Owl | Bird | | SE |
| Haliaeetus leucocephalus | Bald Eagle | Bird | LT,PDL | SE |
| Lanius ludovicianus | Loggerhead Shrike | Bird | No Status | SE |
| Tyto alba | Barn Owl | Bird | | SE |
| Lynx rufus | Bobcat | Mammal | No Status | |
| Myotis sodalist | Indiana Bat or Social Myotis | Mammal | LE | SE |
| Sylvilagus aquaticus | Swamp Rabbit | Mammal | | SE |
| Androsace occidentalis | Western Rockjasmine | Plant | | ST |
| Azolla caroliniana | Carolina Mosquito-fern | Plant | | ST |
| Bacopa rotundifolia | Roundleaf Water-hyssop | Plant | | ST |
| Callirhoe triangulata | Clustered Poppy-mallow | Plant | | SX |
| Carex gigantean | Large Sedge | Plant | | ST |
| Carex gravida | Heavy Sedge | Plant | | SE |
| Carya pallida | Sand Hickory | Plant | | SE |
| Carya texana | Black Hickory | Plant | | SE |
| Catalpa speciosa | Northern Catalpa | Plant | | SR |
| Chelone obliqua var. speciosa | Rose Turtlehead | Plant | | WL |
| Chrysopsis villosa | Hairy Golden-aster | Plant | | ST |
| Clematis pitcheri | Pitcher Leather-flower | Plant | | SR |
| Conyza canadensis var. pusilla | Fleabane | Plant | | SX |
| Cyperus pseudovegetus | Green Flatsedge | Plant | | SR |
| Echinodorus cordifolius | Creeping Bur-head | Plant | | SE |
| Euphorbia obtusata | Bluntleaf Spurge | Plant | | SE |
| Gentiana puberulenta | Downy Gentian | Plant | | ST |
| Gleditsia aquatica | Water-locust | Plant | | SE |
| Hibiscus moscheutos ssp. lasiocarpos | Hairy-fruited Hibiscus | Plant | | SE |
| Hypericum adpressum | Creeping St. John's-wort | Plant | | SE |
| Iresine rhizomatosa | Eastern Bloodleaf | Plant | | SR |
| Isoetes melanopoda | Blackfoot Quillwort | Plant | | ST |

**Table 15: Endangered, Threatened or Rare Species – Knox County, Indiana**

| Species Name | Common Name | Type | Federal | State |
|---|---|---|---|---|
| Monarda bradburiana | Eastern Bee-balm | Plant | | SE |
| Orobanche ludoviciana | Louisiana Broomrape | Plant | | SE |
| Passiflora incarnata | Purple Passion-flower | Plant | | SR |
| Penstemon tubaeflorus | Tube Penstemon | Plant | | SX |
| Phacelia ranunculacea | Blue Scorpion-weed | Plant | | SE |
| Plantago cordata | Heart-leaved Plantain | Plant | | SE |
| Prenanthes aspera | Rough Rattlesnake-root | Plant | | SR |
| Psoralea tenuiflora | Few-flowered Scurf-pea | Plant | | SX |
| Pteridium aquilinum var. pseudocaudatum | Bracken Fern | Plant | | SX |
| Rubus alumnus | A Bramble | Plant | | SX |
| Rudbeckia fulgida var. fulgida | Orange Coneflower | Plant | | WL |
| Silene regia | Royal Catchfly | Plant | | ST |
| Strophostyles leiosperma | Slick-seed Wild-bean | Plant | | ST |
| Taxodium distichum | Bald Cypress | Plant | | ST |
| Trichostema dichotomum | Forked Bluecurl | Plant | | SR |
| Vitis palmate | Catbird Grape | Plant | | SR |
| Barrens – sand | Sand Barrens | Natural Community | | SG |
| Forest - floodplain wet-mesic | Wet-mesic Floodplain Forest | Natural Community | | SG |
| Forest – upland mesic | Upland Forest | Natural Community | | SG |
| Lake – pond | Pond | Natural Community | | SG |
| Wetland - swamp forest | Forested Swamp | Natural Community | | SG |

Fed: LE = Endangered; LT = Threatened; C = candidate; PDL = proposed for delisting
State: SE = state endangered; ST = state threatened; SR = state rare; SSC = state species of special concern; SX = state extirpated; SG = state significant; WL = watch list

**Source:**
Indiana Natural Heritage Data Center
Division of Nature Preserves
Indiana Department of Natural Resources

This data is not the result of comprehensive county surveys.

The OAQ is not aware of any federally-listed endangered species within the vicinity of this source or within the town of Edwardsport, Indiana. Based on the location of the Edwardsport plant and the air quality analysis done, the impact of the modification to this industrial area would not affect habitats of endangered species; therefore; emissions from this source will not adversely affect any federally-listed endangered species or any state-listed endangered species.

## Public Health and Safety

The Office of Air Quality (OAQ) issues technically sound permits that are protective of public health. Within the boundaries of the law, the OAQ has conducted appropriate analysis of the impacts of this proposed facility on human health. State Implementation Plan (SIP) requirements are examples of health-based standards, because the SIP requirements were proposed by the state and approved by the U.S. EPA for the purposes of maintaining the National Ambient Air Quality Standards (NAAQS). These standards are health-based standards and based on the assessment of public health risks associated with certain levels of pollution in the ambient environment. The Clean Air Act (CAA) requires each state to develop air quality plans and outlines how the standards will be met.

U.S. EPA has established ambient levels that are protective of human health. Anticipated emissions can be modeled and the resulting ambient levels compared to the federal standard. If levels are not expected to increase above U.S. EPA's ambient standard, it is appropriate to conclude that the proposed facility will not pose an increased threat to public health.

## Noise, Odor and Zoning

The Office of Air Quality (OAQ) does not have jurisdiction over noise pollution, odor and zoning.

## Environmental Justice (EJ)

Based on the 2000 US Census, there are 12.5% of Indiana residents who identified themselves as racial minority. An area is classified as High Racial Minority if it falls between 18.75% to 24.99%. Knox County, IN, where the Edwardsport Generating Station is located does not fall under this classification.

Based on the 1990 US Census, 28% of Indiana residents lived in households that received an income less than or equal to twice the poverty level. This is classified a Low Income Household. Knox County, IN, where the Edwardsport Generating Station is located does not fall under this classification.

If the source being reviewed is going to be located in an area considered to be either a High Racial Minority or Low Income Household, the OAQ attempts to publish the notice for the public review in a non-English newspaper, and holds a public meeting prior to the issuing a final action. Since Knox County, where the Edwardsport Generating Station is located is neither of these classifications, the OAQ will only publish the notice in a most circulated newspaper in the area.

For more information on Environmental Justice (EJ), please refer to www.in.gov/idem/your_environment/community_involvement/ej/.

## Recommendation and Conclusion

(1) Based on the facts, conditions and evaluations made, OAQ recommends to the IDEM Commissioner that the SSM 083-23529-00003 and SPM 083-23531-00003 be approved.

(2) A copy of the preliminary findings is also available on the Internet at: www.in.gov/idem/permits/air/pending.html.

(3) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM's Guide for Citizen Participation and Permit Guide on the Internet at: www.in.gov/idem/permits/guide/.

## TSD Appendices

The following are the appendices of this TSD:

(1) Appendix A – Emissions Calculations

(2) Appendix B – PSD BACT Analyses

(3) Appendix C – Air Quality Impact Analysis

(4) Appendix D – Proposed Changes to Part 70 Operating Permit

## IDEM Contact

Questions regarding this proposed permit can be directed to:

Kimberly Cottrell
Indiana Department Environmental Management
Office of Air Quality
100 North Senate Avenue
MC 61-53, Room 1003
Indianapolis, Indiana 46204-2251
Toll free (within Indiana): 1-800-451-6027 extension 3-0870
Or dial directly: (317) 233-0870
kcottrel@idem.in.gov

Please refer to Significant Source Modification No.: 083-23529-00003 and Significant Permit Modification No.: 083-23531-00003 in all correspondence.

# Indiana Department of Environmental Management
# Office of Air Quality

Appendix A to the
Technical Support Document (TSD)
Emission Calculations

**Source Description and Location**

| | |
|---|---|
| Company Name: | Duke Energy Indiana - Edwardsport Generating Station |
| Address City IN Zip: | State Road 67, Edwardsport, IN 47258 |
| County: | Knox |
| SIC / NAICS Code: | 4911 |
| Source Modification No.: | 083-23529-00003 |
| Permit Modification No.: | 083-23531-00003 |
| Permit Reviewer: | Kimberly Cottrell |
| Date: | November 14, 2007 |

**Summary of Potential to Emit**

| | **Uncontrolled Potential To Emit** (ton/yr) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Process / Emission Unit** | **CO** | **$NO_X$** | **PM** | **$PM_{10}$** | **$PM_{2.5}$** | **$SO_2$** | **VOC** | **Single HAP** | **Single HAP Name** | **Combination HAPs** |
| Fugitive Emissions (Paved Roads, Dropping of Coal onto Pile, Unpaved Road Emissions, Slag Loading onto Storage Pile) | | | 56.00 | 17.90 | 3.30 | | | - | - | - |
| Particulate Emission from Dust Collecting Systems | - | - | 6,010.00 | 6,010.00 | 6,010.00 | - | - | - | - | - |
| Gasification Preheater | | | | | | | | | | |
| Auxiliary Boiler | 61.76 | 102.94 | 5.59 | 5.59 | 5.59 | 0.55 | 4.04 | | | |
| Flare Normal Operation (Natural Gas-Fired) | 0.96 | 1.15 | 0.09 | 0.09 | 0.09 | 0.01 | 0.06 | Total HAPS for heaters, auxiliary boiler, thermal oxidizer and flare | | |
| Thermal Oxidizer | 1.39 | 1.65 | 0.13 | 0.13 | 0.13 | 87.01 | 0.09 | | | |
| Combustion Turbine Gas Conditioning Preheaters | 4.40 | 7.30 | 0.30 | 0.30 | 0.30 | 0.03 | 1.70 | 0.0018 | Hexane | 1.47 |
| Combined Cycle Combustion Turbine with HRSG | 832.20 | 1,989.00 | 345.20 | 342.50 | 342.50 | 254.00 | 29.00 | 5.91 | Formaldehyde | 11.19 |
| Cooling Tower | - | - | 559.20 | 559.20 | 559.20 | - | - | - | - | - |
| Diesel Fired Emergency Generator | 3.03 | 7.15 | 0.10 | 0.08 | 0.07 | 0.22 | 0.39 | 0.04 | Propylene | 0.04 |
| Diesel Fired Emergency Fire Pump | 0.70 | 3.26 | 0.23 | 0.23 | 0.23 | 0.22 | 0.26 | 0.003 | Propylene | 0.008 |
| Equipment Trip or Malfunction Events | 13.11 | 9.04 | 4.13 | 4.13 | 4.13 | 16.45 | 0.43 | - | - | - |
| **Totals:** | **917.56** | **2,121.48** | **6,980.96** | **6,940.14** | **6,925.53** | **358.49** | **35.98** | | | **12.71** |

| | **Limited Potential To Emit** (ton/yr) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Process / Emission Unit** | **CO** | **$NO_X$** | **PM** | **$PM_{10}$** | **$PM_{2.5}$** | **$SO_2$** | **VOC** | **Single HAP** | **Single HAP Name** | **Combination HAPs** |
| Paved Road Emissions | - | - | 16.07 | 3.14 | 0.47 | - | - | - | - | - |
| Dropping of Coal from conveyor onto Coal Pile | - | - | 3.48 | 1.64 | 0.25 | - | - | - | - | - |
| Unpaved Road Emissions | - | - | 0.01 | 0.00 | 0.00 | - | - | - | - | - |
| Slag Loading on to Storage Pile | - | - | 0.39 | 0.18 | 0.03 | - | - | - | - | - |
| Emissions due to Wind Erosion | - | - | 10.18 | 5.09 | 0.76 | - | - | - | - | - |
| Particulate Emission from Dust Collecting Systems | - | - | 6.01 | 6.01 | 6.01 | - | - | - | - | - |
| Auxiliary Boiler | 61.76 | 102.94 | 5.59 | 5.59 | 5.59 | 0.55 | 4.04 | | | |
| Flare Normal Operation (Natural Gas-Fired) | 0.96 | 1.15 | 0.09 | 0.09 | 0.09 | 0.01 | 0.06 | Total HAPS for heaters, auxiliary boiler, thermal oxidizer and flare | | |
| Thermal Oxidizer | 1.39 | 1.65 | 0.13 | 0.13 | 0.13 | 87.01 | 0.09 | | | |
| Combustion Turbine Gas Conditioning Preheaters | 4.38 | 7.27 | 0.33 | 0.33 | 0.33 | 0.03 | 1.66 | 0.0018 | Hexane | 1.47 |
| Combined Cycle Combustion Turbine with HRSG | 832.15 | 1,989.00 | 342.52 | 342.52 | 342.52 | 254.04 | 29.87 | 5.91 | Formaldehyde | 11.19 |
| Cooling Tower | - | - | 27.96 | 27.96 | 27.96 | - | - | - | - | - |
| Diesel Fired Emergency Fire Pump | 0.70 | 3.26 | 0.23 | 0.23 | 0.23 | 0.22 | 0.26 | 0.003 | Propylene | 0.008 |
| Equipment Trip or Malfunction Events | 13.11 | 9.04 | 4.13 | 4.13 | 4.13 | 16.45 | 0.43 | - | - | - |
| Diesel Fired Emergency Generator | 3.03 | 7.15 | 0.10 | 0.08 | 0.07 | 0.22 | 0.39 | 0.04 | Propylene | 0.04 |
| **Totals:** | **917.49** | **2,121.46** | **417.19** | **397.11** | **388.55** | **358.53** | **36.82** | | | **12.71** |

# Index of Calculation Details

# Criteria Pollutant Emissions - Normal Operation
## Paved Road Emissions

| Emission Point ID: | F-1 | Truck Traffic |
|---|---|---|

| | Truck Capacity | Full Truck | Empty Truck | Average |
|---|---|---|---|---|
| Weight *(tons)* = | 40 | 40 | 20 | 30 |

| Materials Delivered by Truck | Load Size | # Trucks | | | Amount of Material Loaded | Trip Distance | Total VMT |
|---|---|---|---|---|---|---|---|
| | *tons* | *truck frequency* | | *trucks/yr* | *tons/yr* | *miles/trip* | *miles* |
| Coal | 30 | 200 | per day | 73,000 | 2,190,000 | 0.84 | 61,247 |
| Sulfur | 30 | 13 | per day | 4,745 | 142,350 | 0.7 | 3,255 |
| Slag | 30 | 25 | per day | 9,125 | 273,750 | 0.5 | 4,845 |
| Cooling Tower Treatment Chemicals | 30 | 30 | per week | 1,560 | 46,800 | 0.78 | 1,217 |
| | | | | | | Total VMT/yr = | **70,564** |

| | Units | PM | $PM_{10}$ | $PM_{2.5}$ |
|---|---|---|---|---|
| W = Average Vehicle Weight = | *tons* | 30 | 30 | 30 |
| k = Particle Size Number = | *unitless* | 0.082 | 0.016 | 0.0024 |
| SL = Road Surface Silt Loading = | *$g/m^2$* | 0.4 | 0.4 | 0.4 |
| E = Emission Factor = | *lbs/VMT* | 0.91 | 0.18 | 0.03 |
| Total VMT = | *miles* | 70,564 | 70,564 | 70,564 |
| **PTE = Uncontrolled Emissions =** | ***tons/yr*** | **16.07** | **3.14** | **0.47** |

**Methodology**:
Emission factors are based on AP-42, Section 13.2.1 - Paved Roads.
Load Size = Average Vehicle Weight
Annual Amount of Material Loaded = Load Size x # Trucks
Trip Distance includes truck traveling both empty and full while inside the facility.
Trip Distances were estimated by Duke Energy Indiana based on the engineering plans for the project.
Total Vehicle Miles Traveled (VMT) = # Trucks x Trip Distance
Emissions estimates account for a 50% control efficiency due to incorporation of a dust minimization plan on roadway surfaces at the proposed IGCC plant.

$$E = k \times (sL/2)^{0.65} \times (W/3)^{1.5}$$

Where:
E = Emission Factor (lbs/VMT)
k = Particle Size Number = lbs/VMT
SL= Road Surface Silt Loading = $g/m^2$ [RCategory: Ubiquitous Baseline]
W = Average Vehicle Weight (tons)

Emissions (tons/yr) = [Emission Factor (lbs/VMT) x Total Vehicle Miles Travel (miles/yr) ] / 2000 (lb/ton)

## Criteria Pollutant Emissions - Normal Operation
### Dropping of Coal from Conveyor onto Coal Pile

| Emission Point ID: | F-2 | Coal Operations |
|---|---|---|

| Coal Pile Operations | Coal Moved | Emission Factors | | | Potential to Emit | | |
|---|---|---|---|---|---|---|---|
| | | **PM** | **$PM_{10}$** | **$PM_{2.5}$** | **PM** | **$PM_{10}$** | **$PM_{2.5}$** |
| | *tons/yr* | *lb/ton coal moved* | *lb/ton coal moved* | *lb/ton coal moved* | *tons/yr* | *tons/yr* | *tons/yr* |
| Dropping of Coal from Conveyor onto Coal Pile | 2,190,000 | 0.0032 | 0.0015 | 0.0002 | 3.48 | 1.64 | 0.25 |

**Methodology**

Emission factors are based on AP 42 Chapter 13.2.4 "Aggregate Handling and Storage Piles", 11/06.

Emission Factor (lb/ton of coal moved) = $k \times 0.0032 \times (U/5)^{1.3} / (M/2)^{1.4}$

Where:

k = particle size multiplier (dimensionless) = 0.053 (for $PM_{2.5}$)
0.35 (for $PM_{10}$)
0.74 (for PM)

U = mean wind speed (mph) = 15 [Reference: Value provided by the Source]

M = moisture content of coal (%) = 4.5 [Reference: Value provided by the Source]

# Criteria Pollutant Emissions - Normal Operation
## Unpaved Road Emissions
### Equipment Traffic Associated with Pile Maintenance on Coal Pile (F-2)

| | | |
|---|---|---|
| Daily Travel Distance (D) = | 900 | ft/hour |
| Annual Vehicle Miles Traveled (VMT) = | 126 | VMT/yr |
| W = Average Vehical Weight = | 10,440 | pounds |
| W = Average Vehical Weight = | 5.22 | tons |
| P = number of days in a year with at least 0.01 inch of precipitation = | 130 | |
| CE = Fugitive Dust Control Efficiency = | 95% | |

| | Units | PM | $PM_{10}$ | $PM_{2.5}$ |
|---|---|---|---|---|
| k = Particle Size Number = | *unitless* | 4.9 | 1.5 | 0.15 |
| s = Road Surface Silt Loading = | *$g/m^2$* | 4.8 | 4.8 | 4.8 |
| a = empirical constant = | | 0.7 | 0.9 | 0.9 |
| b = empirical constant = | | 0.45 | 0.45 | 0.45 |
| E = Emission Factor = | *lbs/VMT* | 3.31 | 0.84 | 0.08 |
| $E_{ext}$ = Annual Size-Specific Emission Factor = | *lbs/VMT* | 2.13 | 0.54 | 0.05 |

| | | | | |
|---|---|---|---|---|
| PTE = Uncontrolled Emissions = | *tons/yr* | 0.13 | 0.034 | 0.0034 |
| **PTE = Controlled Emissions =** | *tons/yr* | **0.01** | **0.002** | **0.0002** |

**Methodology**

All in-plant roadways are paved; however, the area adjacent to the coal pile is assumed to be "unpaved roads" for calculation purposes.

Vehicle traffic based on equipment moving 900 feet per hour. Feet/hr is an estimated distance.
Emission factors are based on AP 42, Chapter 13.2.2, "Unpaved Roads", December 2003, Equation 1a (Unpaved roads at industrial sites).
VMT/yr = 126 [Reference: Value provided by the source]
Emission Factor 'E' (lb/VMT) = k x (s/12)a x (W/3)b
Annual Size-Specific Emission Factor 'Eext' (lb /VMT) = E x [(365-P)/365]
Uncontrolled PTE = [Eext (lb/VMT)] x [Vehicle Miles Travel per Year (VMT/yr)] / 2000 (lb/ton)
Potential Emission = [Eext (lb/VMT)] x [Vehicle Miles Travel per Year (VMT/yr)] x [Fugitive Dust Control Efficiency (95%)] / 2000 (lb/ton)

## Slag Loading on to Storage Pile

| Slag Pile Operations | Tons of Slag Moved | Emission Factors | | | Potential to Emit | | |
|---|---|---|---|---|---|---|---|
| | | **PM** | **$PM_{10}$** | **$PM_{2.5}$** | **PM** | **$PM_{10}$** | **$PM_{2.5}$** |
| | *(tons/yr)* | *(lb/ton slag moved)* | *(lb/ton slag moved)* | *(lb/ton slag moved)* | *(tons/yr)* | *(tons/yr)* | *(tons/yr)* |
| Dropping of slag from Conveyor onto slag Pile | 180,000 | 0.0043 | 0.0021 | 0.0003 | 0.39 | 0.18 | 0.03 |

| Emission Point ID # | |
|---|---|
| Slag Pile Operations | F-2 |

**Methodology**

Emission factor based on AP 42 Chapter 13.2.4 "Aggregate Handling and Storage Piles", Equation 1.

Emission Factor (lb/ton of slag moved) = k x (0.0032) x (U/5)1.3 / (M/2)1.4

Where:

k = particle size multiplier (dimensionless) = 0.74 for PM, 0.35 for PM10 and 0.053 for PM2.5 [Reference: page no. 13.2.4-4 in AP 42]

U = mean wind speed (mph) = 15 [Reference: Value provided by the Source]

M = moisture content of slag (%) = 4.5 [Reference: Value provided by the Source]

## Emissions due to Wind Erosion

| Description | Surface Area | Emission Factors PM | Emission Factors $PM_{10}$ | Emission Factors $PM_{2.5}$ | Potential to Emit PM | Potential to Emit $PM_{10}$ | Potential to Emit $PM_{2.5}$ |
|---|---|---|---|---|---|---|---|
| | *($m^2$)* | *($g/m^2$)* | *($g/m^2$)* | *($g/m^2$)* | *(tons/yr)* | *(tons/yr)* | *(tons/yr)* |
| Wind Erosion from Active Coal Storage Pile | 15,706 | 623.7 | 311.9 | 46.8 | 2.70 | 1.35 | 0.20 |
| Wind Erosion from Inactive Coal Storage Pile | 34,260 | 623.7 | 311.9 | 46.8 | 5.89 | 2.94 | 0.44 |
| Wind Erosion from Slag Pile | 9,253 | 623.7 | 311.9 | 46.8 | 1.59 | 0.80 | 0.12 |
| | | | | **Total** | **10.18** | **5.09** | **0.76** |

**Methodology**
Emission factors are based on AP 42, Chapter 13.2.5-3, "Industrial Wind Erosion", 4th Edition, Equations 2 and 3.
'Active Coal Storage Pile' supplies the coal for gasification process.
'Inactive Coal Storage Pile' is a long-term coal storage pile and supplies the coal for the 'Active Coal Pile'.

$$\text{Emission factor} = k \sum_{i=1}^{N} P_i$$

| Emission Point ID # | |
|---|---|
| Wind Erosion | F-2 |

$P_i = 58\,(u^* - u_t)^2 + 25\,(u^* - u_t)$

$u^* = 0.053\,u_{10}$

Where:

Emission Factor is in $g/m^2$. $1\ ft^2 = 0.093\ m^2$

k = particle size multiplier (unitless) = 1.0 for PM, 0.5 for PM10 and 0.075 for PM2.5 [Reference: Subsection 13.2.5.3 in AP 42]

N = number of disturbances per year = 365 [Reference: Subsection 13.2.5.3 in AP 42, N= 365 for a surface disturbed daily]

P = erosion potential corresponding to the observed (or probable) fastest mile of wind for the ith period between disturbances, $g/m^2$

by source]

$u_t$ = threshold friction velocity (m/s) = 1.12 [Reference: Table 13.2.5-2 in PA-42, uncrushed coal pile]

$u^*$ = friction velocity (m/s) = $0.053\,u_{10}$ = 0.053 x 22.35 = 1.185 m/s

Potential Emission (tons/yr) = [Emission Factor (g/m2) x Total surface area of pile (m2) x [Fugitive Dust Control Efficiency (50%)] / [453.59 (g/lb) x 2000 (lb/ton)]

Conservatively, it is assumed that wind distribution is equal to all portions of the pile (including sides).

| Pile Surface Characteristics | | |
|---|---|---|
| **Active Coal Pile** | **Inactive Coal Pile** | **Slag Pile** |
| Shape: Cylindrical Pile | Shape: Irregular shape Prism | Shape: Square Prism |
| Diameter (ft) = 205 | Top surface area ($m^2$) = 28,469 | Height (m) = 2.4 |
| Height (ft) = 80 | Height (m) = 6.1 | Side Length (m) = 91.4 |
| | Total edge distance (m) = 950 | Top surface area ($m^2$) = 8,361 |
| | Side surface area ($m^2$) = 5,791 | Side surface area ($m^2$) = 892 |
| | Total surface area ($m^2$) = 34,260 | Total surface area ($m^{2)}$ = 9,253 |

## Particulate Emissions from Dust Collecting Systems

| Description | Emission Point ID # | Dust Collection System Exhaust Flow Rate | Emission Rates | | | | Potential Emissions |
|---|---|---|---|---|---|---|---|
| | | | $PM / PM_{10} / PM_{2.5}$ | $PM / PM_{10} / PM_{2.5}$ | $PM / PM_{10} / PM_{2.5}$ | $PM / PM_{10} / PM_{2.5}$ | $PM / PM_{10} / PM_{2.5}$ |
| | | *acfm* | *gr/acf* | *gr/min* | *gr/hr* | *lb/hr* | *tons/yr* |
| Dust Collection System for Coal Processing (Gasification) | S-1A | 40,000 | 0.001 | 40 | 2,400 | 0.34 | 1.50 |
| Dust Collection System for Coal Processing (Coal Receiving) | S-1B | 40,000 | 0.001 | 40 | 2,400 | 0.34 | 1.50 |
| Dust Collection System for Lime Silo Baghouses | S-1C | 40,000 | 0.001 | 40 | 2,400 | 0.34 | 1.50 |
| Dust Collection System for Coal Pile Drop Point Baghouses | S-1D | 40,000 | 0.001 | 40 | 2,400 | 0.34 | 1.50 |
| | | | | | | Total | 6.01 |

**Methodology**
1 grain = 0.000143 lb
Dust Collection System Exhaust Flow Rate in 'acfm' and Emission Rate in 'grains/acf' are engineering estimates supplied by the vendor.
Emission Rate (grains/minute) = [Exhaust Flow Rate (acfm)] x [Emission Rate (grains/acf)]
Emission Rate (grains/hour) = [Emission Rate in (grains/minute)] x [60 (minute/hour)]
Emission Rate (lb/hour) = [Emission Rate (grains/hour)] x [0.000143 (lb/grain)]
Potential Emission (tons/yr) = [Emission Rate (lb/hour)] x 8760 (hrs/yr) /2000 (lb/ton)]

## Criteria Pollutant Emissions - Normal Operation
### Natural Gas Fired Gasification Preheater

Number of Units = 2
Combined Maximum Heat Input (MMBtu/hr) = 38.2

| Emission Point ID # | |
|---|---|
| GPREHEAT1 AND 2 | S-5A1 and S-5A2 |

| Pollutant | Gasif. ATM Vent Emissions During Startup (lbs/event) | STARTUP EVENTS PER YEAR | STARTUP EMISSIONS | |
|---|---|---|---|---|
| | | | Worst Case LB/HR | TONS/YR |
| $SO_2$ | 1 | 76 | 0.03 | 0.04 |
| $NO_X$ * | 172 | | 3.75 | 6.5 |
| $PM/PM_{10}/PM_{2.5}$ | 13 | | 0.30 | 0.5 |
| CO | 145 | | 3.20 | 5.5 |
| VOC | 9 | | 0.21 | 0.3 |

**Methodology**

Pre-heaters used only during startup of gasifier trains. Estimate based on a worst case 1st year total of 38 startups per train.

Emission factors (except Nox) are from AP 42, Chapter 1: External Combustion Sources, Section 1.4: Natural Gas Combustion, 7/98.

* Emission factor for $NO_X$ is based on worst case startup value.

All PM (total, condensable and filterable) is assumed to be less than 1 micrometer in diameter. Therefore, the PM emission factor is also used to estimate PM10 and PM2.5 emissions. [Reference: Footnote of Table 1.4-2 of AP 42].

## Criteria Pollutant Emissions - Normal Operation
Auxiliary Boiler

Number of Units = 1
Maximum heat input (MMBtu/hr) = 300

| Emission Point ID # | |
|---|---|
| AUXBLR | S-6 |

| Pollutant | Emission Factor | | Emission Rate | Potential Emissions |
|---|---|---|---|---|
| | *lb/10$^6$ SCF* | *lb/MMBtu* | *lb/hr* | *tons/yr* |
| $SO_2$ | 0.75 | 0.0007 | 0.22 | 0.55 |
| $NO_X$ | 140 | 0.1373 | 41.18 | 102.94 |
| $PM/PM_{10}/PM_{2.5}$ | 7.6 | 0.0075 | 2.24 | 5.59 |
| CO | 84 | 0.0824 | 24.71 | 61.76 |
| VOC | 5.5 | 0.0054 | 1.62 | 4.04 |

**Methodology**

Emission factors are from vendor guarantees. Includes low $NO_x$ burner (actual CO factor will be 34 versus 84. 84 used for estimated purposes only)

Number of hours of operation per year = 5000

To convert from lb/10$^6$ scf to lb/MMBtu, divide by 1,020. [Reference: Footnote of Table 1.4-2 in AP 42]

Emission Factor (lb/MMBtu) = [Emission Factor (lb/10$^6$ scf)] /1020

Emission Rate (lb/hr) = [Maximum Heat Input (MMBtu/hr)] x [Emission Factor (lb/MMBtu)]

Potential Total Emission (tons/yr) = [Emission Rate (lb/hr)] x [8760 (hrs/yr)] / [2000 (lb/ton)]

All PM (total, condensable and filterable) is assumed to be less than 1 micrometer in diameter. Therefore, the PM emission factor is also used to estimate PM10 and PM2.5 emissions. [Reference: Footnote of Table 1.4-2 of AP 42].

## Criteria Pollutant Emissions - Normal Operation
Flare Normal Operation (Natural Gas-Fired)

Number of Unit = 1
Maximum heat input (MMBtu/hr ) = 2.67

| Emission Point ID # | |
|---|---|
| FLR | S-3 |

| Pollutant | Emission Factor | | Emission Rate | Potential Emissions |
|---|---|---|---|---|
| | *lb/10⁶ SCF* | *lb/MMBtu* | *lb/hr* | *tons/yr* |
| $SO_2$ | 0.6 | 0.0006 | 0.002 | 0.007 |
| $NO_X$ | 100 | 0.0980 | 0.262 | 1.147 |
| $PM/PM_{10}/PM_{2.5}$ | 7.6 | 0.0075 | 0.020 | 0.087 |
| CO | 84 | 0.0824 | 0.220 | 0.963 |
| VOC | 5.5 | 0.0054 | 0.014 | 0.063 |

**Methodology**
Maximum heat input of 2.67 MMBtu/hr based on 1.23 MMBtu/hr for flare pilot and 1.44 MMBtu/hr for sweep enrichment gas/flare purge gas.
Emission factors are from AP 42, Chapter 1: External Combustion Sources, Section 1.4: Natural Gas Combustion, 7/98.
Emissions shown are based on using 100% natural gas.
Number of hours of operation per year = 8760
To convert from lb/$10^6$ scf to lb/MMBtu, divide by 1,020. [Reference: Footnote of Table 1.4-2 in AP
Emission Factor (lb/MMBtu) = [Emission Factor (lb/$10^6$ scf)] /1020
Emission Rate (lb/hr) = [Maximum Heat Input (MMBtu/hr)] x [Emission Factor (lb/MMBtu)]
Potential Total Emission (tons/yr) = [Emission Rate (lb/hr)] x [8760 (hrs/yr)] / [2000 (lb/ton)]
All PM (total, condensable and filterable) are assumed to be less than 1 micrometer in diameter. Therefore, the PM emission factor is also used to estimate PM10 and PM2.5 emissions. [Reference: Footnote of Table 1.4-2 of AP 42].

## Criteria Pollutant Emissions - Normal Operation

Thermal Oxidizer

Number of Unit = 1
Maximum heat input (MMBtu/hr ) = 3.85

| Emission Point ID # | |
|---|---|
| THRMOX | S-4 |

| Pollutant | Emission Factor | | Emission Rate | Potential Emissions |
|---|---|---|---|---|
| | *lb/10⁶ SCF* | *lb/MMBtu* | *lb/hr* | *tons/yr* |
| $SO_2$ * | - | 5.16 | 19.87 | 87.01 |
| $NO_X$ | 100 | 0.0980 | 0.38 | 1.65 |
| $PM/PM_{10}/PM_{2.5}$ | 7.6 | 0.0075 | 0.03 | 0.13 |
| CO | 84 | 0.0824 | 0.32 | 1.39 |
| VOC | 5.5 | 0.0054 | 0.02 | 0.09 |

**Methodology**

Emission factor (except $SO_2$) are from AP 42, Chapter 1: External Combustion Sources, Section 1.4: Natural Gas Combustion, 7/98.

* Emission factor of $SO_2$ is based on vendor guaranteed emission factor.

Emissions shown are based on using 100% natural gas.

Sulfur stream from sulfur pit based on 0.31 lb mol/hr of sulfur.

Continuous emissions include the pilot, hot standby and sulfur pit vent.

Emissions reflect the thermal oxidizer combusting natural gas to support hot standby and the pilot.

Number of hours of operation per year = 8760

To convert from lb/$10^6$ scf to lb/MMBtu, divide by 1,020. [Reference: Footnote of Table 1.4-2 in AP 42]

Emission Factor (lb/MMBtu) = [Emission Factor (lb/$10^6$ scf)] /1020

Emission Rate (lb/hr) = [Maximum Heat Input (MMBtu/hr)] x [Emission Factor (lb/MMBtu)]

Potential Total Emission (tons/year) = [Emission Rate (lb/hr)] x [8760 (hrs/year)] / [2000 (lb/ton)]

All PM (total, condensable and filterable) is assumed to be less than 1 micrometer in diameter. Therefore, the PM emission factor is also used to estimate PM10 and PM2.5 emissions. [Reference: Footnote of Table 1.4-2 of AP 42].

## Criteria Pollutant Emissions - Normal Operation
Combustion Turbine Gas Conditioning Preheaters

Number of Unit = 2
Maximum heat input (MMBtu/hr ) = 10

| Emission Point ID # | |
|---|---|
| TPREHEAT1 and 2 | S-5B1 and S-5B2 |

| Pollutant | Emission Factor | | Emission Rate | Potential Emissions |
|---|---|---|---|---|
| | *lb/10$^6$ SCF* | *lb/MMBtu* | *lb/hr* | *tons/yr* |
| $SO_2$ | 0.6 | 0.0006 | 0.006 | 0.03 |
| $NO_X$ * | - | 0.1660 | 1.66 | 7.27 |
| $PM/PM_{10}/PM_{2.5}$ | 7.6 | 0.0075 | 0.075 | 0.33 |
| CO * | - | 0.1000 | 1.00 | 4.38 |
| VOC * | - | 0.0380 | 0.38 | 1.66 |

**Methodology**

Emission factor (except NOx and CO) are from AP 42, Chapter 1: External Combustion Sources, Section 1.4: Natural Gas Combustion, 7/98.

Emissions shown are based on using 100% natural gas.

* Emission factors for NOx, VOC and CO are based on vendor guaranteed emission factor.

Number of hours of operation per year = 8760

To convert emission factor from lb/10$^6$ scf to lb/MMBtu, divide the by 1,020. [Reference: Footnote of Table 1.4-2 in AP 42]

Emission Factor (lb/MMBtu) = [Emission Factor (lb/10$^6$ scf)] / 1020

Combined Emission Rate of 2 Units (lb/hr) = [Combined Maximum Heat Input of 2 Units (MMBtu/hr)] x [Emission Factor (lb/MMBtu)]

Combined Potential Total Emission of 2 Units (tons/yr) = [Combined Emission Rate of 2 Units (lb/hr)] x 2500 (hrs/yr)] / [2000 (lb/ton)]

All PM (total, condensable and filterable) is assumed to be less than 1 micrometer in diameter. Therefore, the PM emission factor is also used to estimate PM10 and PM2.5 emissions. [Reference: Footnote of Table 1.4-2 of AP 42].

## Criteria Pollutant Emissions - Normal Operation

Potential to Emit of One Combined Cycle Combustion Turbine 'CT' with Heat Recovery Steam Generator 'HRSG'

Number of CT with HRSG = 2
Maximum Heat Input for each CT (MMBtu/hr) = 2109
Maximum Total Heat Input of 2 CT (MMBtu/hr) = 4218

| Emission Point ID # | |
|---|---|
| CTHRSG1 and 2 | S-2A and S-2B |

| | Operating Conditions | Selective Catalytic Reduction | Hours of Operation | $NO_x$ Emission Rate | $NO_x$ Potential Emissions | CO Emission Rate | CO Potential Emissions | $SO_2$ Emission Rate | $SO_2$ Potential Emissions | VOC Emission Rate | VOC Potential Emissions | $PM/PM_{10}/PM_{2.5}$ Emission Rate | $PM/PM_{10}/PM_{2.5}$ Potential Emissions | $H_2SO_4$* Emission Rate | $H_2SO_4$* Potential Emissions |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | hrs | lb/hr | tons/yr | lb/hr | tons/yr | lb/hr | tons/yr | lb/hr | tons/yr | lb/hr | tons/yr | lb/hr | tons/yr |
| Case 1 | Syngas, 100% Load (59 degs F) | Off | 8,760 | 169.0 | 740.2 | 92.5 | 405.2 | 28.9 | 126.6 | 3.3 | 14.5 | 36.00 | 157.7 | 3.20 | 14.0 |
| Case 2 | Syngas, 60% Load (59 degs F) | Off | 8,760 | 124.0 | 543.1 | 69.0 | 302.2 | 21.1 | 92.4 | 2.4 | 10.5 | 21.60 | 94.6 | 2.30 | 10.1 |
| Case 3 | Syngas, 100% Load (59 degs F) | On | 8,760 | 57.0 | 249.7 | 93.0 | 407.3 | 29.0 | 127.0 | 3.3 | 14.5 | 39.10 | 171.3 | 6.40 | 28.0 |
| **Natural Gas Combustion - One Combustion Turbine with HRSG** | | | | | | | | | | | | | | | |
| Case 4 | Natural Gas, 100% Load (0 degs F) | Off | 8,760 | 189.0 | 827.8 | 88.7 | 388.5 | 1.3 | 5.7 | 3.3 | 14.5 | 18.00 | 78.8 | 0.15 | 0.7 |
| Case 5 | Natural Gas, 60% Load (0 degs F) | Off | 8,760 | 148.0 | 648.2 | 62.7 | 274.6 | 1.0 | 4.4 | 2.3 | 10.1 | 11.00 | 48.2 | 0.11 | 0.5 |
| Case 6 | Natural Gas, 100% Load (0 degs F) | On | 8,760 | 38.0 | 166.4 | 88.7 | 388.5 | 1.3 | 5.7 | 3.3 | 14.5 | 18.10 | 79.3 | 0.29 | 1.3 |
| **Combined Syngas and Natural Gas Combustion - One CT with HRSG** | | | | | | | | | | | | | | | |
| Case 7 | Syngas, 90% Load<br>Natural Gas, 10% Load | Off | 8,500 | 234.0 | 994.5 | 97.9 | 416.1 | 26.3 | 111.8 | 3.4 | 14.9 | 36.00 | 153.0 | 2.76 | 12.1 |

### Worst Case Potential to Emit of Two Combined Cycle CT with HRSG

| | $NO_x$ Emission Rate | $NO_x$ Potential Emissions | CO Emission Rate | CO Potential Emissions | $SO_2$ Emission Rate | $SO_2$ Potential Emissions | VOC Emission Rate | VOC Potential Emissions | $PM/PM_{10}/PM_{2.5}$ Emission Rate | $PM/PM_{10}/PM_{2.5}$ Potential Emissions | $H_2SO_4$* Emission Rate | $H_2SO_4$* Potential Emissions |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | lb/hr | tons/yr | lb/hr | tons/yr | lb/hr | tons/yr | lb/hr | tons/yr | lb/hr | tons/yr | lb/hr | tons/yr |
| Two Combined Cycle CT with HRSG - Worst Case Potential to Emit | 468.0 | 1989.0 | 195.8 | 832.2 | 58.0 | 254.0 | 6.8 | 29.9 | 78.2 | 342.5 | 12.8 | 56.1 |

**Methodology**

Emissions Rates are based on engineering estimates supplied by the vendors.
For Case 1-Case 6: Hours of operation/yr = 8760 For Case 7: Hours of operation/yr = 8500
The HRSG is not supplementally fired.
Potential Total Emission (tons/yr) = [Emission Rate (lb/hr)] x [Hours of Operation (hrs/yr)] / [2000 (lb/ton)]
For a given pollutant, the worst case Potential Emission (tons/yr) corresponds to the highest emission (tons/yr) from all the cases (Case1-Case7).
Syngas results based on using worst case coal conditions.
Worst case operating temperature while combusting Syngas is 59 degrees Fahrenheit.
Worst case operating temperature while combusting natural gas is 0 degrees Fahrenheit.
PM emission is based on both filterable and condensable components. Total PM with SCR includes ammonia sulfate particulates. SCR to be operated in trial mode.
* Five percent (5%) of $SO_2$ emissions are $H_2SO_4$.

Syngas is a gas product resulting from coal gasification process and used as a fuel in power generation plant. It is produced by partial oxidation of combustible constituents of the coal in gasifier. Typical Syngas contains following gas composition (volume %): hydrogen '$H_2$' (25-30%), carbon monoxide 'CO' (30-60%), carbon monoxide '$CO_2$' (5-15%), water vapor '$H_2O$' (2-30%), methane '$CH_4$' (0-5%), hydrogen sulfide '$H_2S$' (0.2-1%), nitrogen '$N_2$' (0.5-4%), argon 'Ar' (0.2-1%) and Ash.

## Criteria Pollutant Emissions - Normal Operation

Emissions from Cooling Tower ($PM/PM_{10}/PM_{2.5}$ and VOC)

| Emission Point ID # | |
|---|---|
| CT1 - CT22 | S-9 |

| Emission Source | Cooling Tower Water Circulation Flow Rate 'CW' *(gal/hour)* | Total Dissolved Solids (TDS) Content in Cooling Tower Make up water 'TDS' *(mg/l)* | Drift Rate 'DR' *(%)* | Potential Emissions PM *(tons/yr)* | Potential Emissions VOC *(tons/yr)* |
|---|---|---|---|---|---|
| Cooling Tower | 15,300,000 | 5,000 | 0.001 | 27.96 | 0* |

**Methodolgy**

Cooling tower drift rate is based on manufacturer's guarantee data.

Cooling tower operates with 1 cycle of concentration (CC) and a circulating water flowrate (CW) of 15,300,000 gal/hour (255,000 gal/min).

Hours of Operation (hrs/yr) = 8760

All PM is assumed to be PM10 and PM2.5, therefore PM = PM10 and PM2.5

* The chemicals to be used in Cooling Tower will not contain VOC and HAPs.

**Potential $PM/PM_{10}/PM_{2.5}$ Emissions Calculation**

Circulating Water TDS = (CC) x (TDS)

$$= \frac{[5000\ (mg/l)]\ [0.001 (g/mg)]\ [3.785\ (L/gal)]}{453.6\ (g/lb)}$$

= 0.042 (lb/gal)

Drift = (DR) (CW) = (0.001%) [15,300,000 (gal/hr)] [8760 (hr/yr)]

Drift = 1,340,280 gal/yr

Drift Particulate = (Drift) (Circulating Water TDS)

Drift Particulate = [1,340,280 (gal/yr)] [0.042 (lb/gal)] = 55,920.1 (lb/yr)

Drift $PM/PM_{10}/PM_{2.5}$ Emission Rate = 55,920 lb/yr = 6.4 lb/hour = 27.96 tons/yr

Drift rate will be 0.0005% based on BACT evaluation. Drift rate of 0.001% was conservatively used for total emissions and regulatory applicability.

## Criteria Pollutant Emissions - Normal Operation
Equipment Trip or Malfunction Events

| | | Air Pollutant | | | | |
|---|---|---|---|---|---|---|
| **Type of Trip** | **Unit** | **$NO_x$** | **$SO_2$** | **CO** | **PM** | **VOC** |
| SRU Trip to Flare | *(lb/event)* | 11.2 | 642.9 | 10.3 | 0.8 | 0.6 |
| SRU Trip to Flare | *(events/yr)* | 12 | 12 | 12 | 12 | 12 |
| SRU Trip to Flare | *(lb/yr)* | 134.4 | 7714.8 | 123.6 | 9.6 | 7.2 |
| Equip. Tripn "A" to Flare | *(lb/event)* | 11.3 | 394.6 | 14.3 | 0.8 | 0.6 |
| Equip. Tripn "A" to Flare | *(events/yr)* | 15 | 15 | 15 | 15 | 15 |
| Equip. Tripn "A" to Flare | *(lb/yr)* | 169.5 | 5919 | 214.5 | 12.0 | 9.0 |
| Equip. Trip "B" to Thermal Oxidizer | *(lb/event)* | 3.5 | 815.2 | 5.3 | 0.2 | 0.2 |
| Equip. Trip "B" to Thermal Oxidizer | *(events/yr)* | 15 | 15 | 15 | 15 | 15 |
| Equip. Trip "B" to Thermal Oxidizer | *(lb/yr)* | 52.5 | 12228.0 | 79.5 | 3.0 | 3.0 |
| CT Trips to Flare | *(lb/event)* | 769.9 | 72.1 | 1120.9 | 358.2 | 36.9 |
| CT Trips to Flare | *(events/yr)* | 23 | 23 | 23 | 23 | 23 |
| CT Trips to Flare | *(lb/yr)* | 17707.7 | 1658.3 | 25780.7 | 8238.6 | 848.7 |
| TGU Trip to Thermal Oxidizer | *(lb/event)* | 2.1 | 897.4 | 4.4 | 0.1 | 0.1 |
| TGU Trip to Thermal Oxidizer | *(events/yr)* | 6 | 6 | 6 | 6 | 6 |
| TGU Trip to Thermal Oxidizer | *(lb/yr)* | 12.6 | 5384.4 | 26.4 | 0.6 | 0.6 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Potential Emissions** | *(lb/yr)* | **18,076.7** | **32,904.5** | **26,224.7** | **8,263.8** | **868.5** |
| **Potential Emissions** | *(tons/yr)* | **9.0** | **16.5** | **13.1** | **4.1** | **0.4** |

**Methodology**

All emission rates are based on engineering estimates supplied by the vendor.

Equipment Trip "A": This is the trip of high pressure $CO_2$/Tail Gas (TG) Recycle Compressor. Such a malfunction results in the opening of a vent through the Low Pressure (LP) absorber to the Flare for duration of 60 minutes.

Equipment Trip "B": This is the trip of high pressure Tail Gas (TG) Recycle Compressor. Such a malfunction results in the opening of a vent to the Thermal Oxidizer for a duration of 60 minutes.

TGU : TGU refers to Tail Gas Unit. It opens tails gas vent from both Sulfur Recovery Units (SRUs) to Thermal Oxidizer. Duration is 30 minutes per event.

CT Trips: CT refers to Combustion Turbine. It opens clean gas vent to the Flare. Vent stays open 1 hour 20 minutes at full rate, then diminishes over 30 additional minutes.

SRU Trips: SRU refers to Sulfur Recovery Unit. It opens acid gas vent to the Flare for 4 minutes, then through the LP Absorber to the Flare for 45 minutes.

Equipment Trip "A", SRU and CT Trips are controlled by the Flare.

Equipment Trip "B" and TGU Trips are controlled by the thermal oxidizer.

Trip Emission (lb/yr) = Trip Emission (lb/event) x Trip Events per Year (events/yr)

Potential Emission (lb/yr) = [SRU Trip Emission (lb/yr) + Equip. Trip "A" emission (lb/yr) + Equip. Trip "B" emission (lb/yr) + CT Trips Emission (lb/yr) + TGU Trip Emission (lb/yr)]

Potential Emission (tons/yr) = Potential Emission (lb/yr) / 2000 (lb/ton)

## Criteria Pollutant Emissions - Normal Operation

### Diesel Fired Emergency Generator

Number of Unit = 1
Rated Horse Power (hp) = 2200

| Emission Point ID # | |
|---|---|
| EMDSL | S-8 |

| Pollutant | Emission Factor | | | | | Potential Emissions |
|---|---|---|---|---|---|---|
| | *lm/MMBtu* | *ng/J* | *ng/sec* | *g/hr* | *$lb/10^6$ scf* | *tons/yr* |
| PM | 6.97E-02 | 3.00E+01 | 4.85E+07 | 1.75E+02 | | 0.10 |
| PM10 | 5.73E-02 | 2.46E+01 | 3.99E+07 | 1.44E+02 | | 0.08 |
| PM2.5 | 4.78E-02 | 2.06E+01 | 3.33E+07 | 1.20E+02 | | 0.07 |
| $SO_2$ * | | | | | 0.0004 | 0.220 |
| $NO_X$ ** | | | | | 0.013 | 7.150 |
| CO | | | | | 0.0055 | 3.025 |
| VOC | | | | | 0.0007 | 0.385 |

**Methodology:**
Emission Factors for $SO_2$, $NO_X$, CO and VOC are from AP 42 (Supplement B 10/96) Table 3.4-1.
Emission Factors for PM, $PM_{10}$ and $PM_{2.5}$ are from AP 42 (Supplement B 10/96) Table 3.4-2.
* SO2 Emission Factor (lb/hp-hr) = 0.00809 x S [Reference: Table 3.4-1 of AP 42]
Where:
S = weight percent sulfur in fuel
= 0.05% [Reference: value provided by the source]
** NOx emission factor is based on assumption that there is no NOX control system.
Hours of operation/yr = 500
Emission Factor (ng/J) = [Emission Factor (lb/MMBtu)] x 430
Emission Factor (ng/second) = [hp x 736 (J/second) x Emission Factor (ng/J)]
Emission Factor (g/hr) = [Emission Factor (ng/second)] x $10^{-9}$ (g/ng) x 3600 (second/hr)]
Potential Total Emission (tons/yr) = [Emission Factor (g/hr) x 500 (hr/yr)] / [453.53 (lb/g) x 2000 (lb/ton)]
Potential Total Emission (tons/yr) = [Emission Factor (lb/hp-hr)] x [Rated Horse Power (hp)] [500 (hrs/yr)] / [2000 (lb/ton)]

### Diesel Fired Emergency Fire Pump

| Emission Point ID # | |
|---|---|
| FIRPMP | S-8 |

Number of Unit = 1
Rated Horse Power (hp) = 420

| Pollutant | Emission Factor | Potential Emissions |
|---|---|---|
| | *$lb/10^6$ scf* | *tons/yr* |
| $SO_2$ | 0.0021 | 0.221 |
| $NO_X$ | 0.031 | 3.255 |
| $PM/PM_{10}$ | 0.0022 | 0.231 |
| CO | 0.0067 | 0.704 |
| VOC | 0.0025 | 0.263 |

**Methodology**
Emission Factors are from AP 42 (Supplement B, 10/96), Table 3.3-1.
Hours of operation/yr = 500
Potential Total Emission (tons/yr) = [Emission Rate (lb/hp-hr)] x [Rated Horse Power (hp)] [500 (hrs/yr)] / [2000 (lb/ton)]
All particulate matter are less than or equal to 10 micron aerodynamic diameter. Therefore, PM is equal to PM10 and PM2.5. [Refrence: Footnote of Table 3.3-1 in AP 42]
Emission factors are conservative estimates. Actual rates will be less based on NSPS IIII emission limitations.

## Criteria Pollutant Emissions - Startup Mode

**Startup Emissions - Flare**

| Pollutant | Startup Train 1 Emission Rate *(lb/event)* | Startup Train 2 Emission Rate *(lb/event)* | Emission Rate of Combined Trains [(1)] *(lb/event)* | Startup Events per Year *(events/yr)* | Worst Case Emission rate [(2)] *(lb/hr)* | Potential Emissions [(3)] *(tons/year)* |
|---|---|---|---|---|---|---|
| $NO_X$ | 96.0 | 85.00 | 181.0 | 76 | 420.7* | 6.9 |
| $SO_2$ | 708.0 | 689.00 | 1397.0 | | 642.9* | 53.1 |
| CO | 495.0 | 416.00 | 911.0 | | 612.5* | 34.6 |
| PM / $PM_{10}$ / $PM_{2.5}$ | 0.8 | 0.80 | 1.6 | | 195.7* | 0.1 |
| VOC | 0.6 | 0.6 | 1.2 | | 20.2* | 0.0 |

**Startup Emissions - Thermal Oxidizer**

| Pollutant | Startup from Ambient *(lb/event)* | Startup Train 1 Emission Rate *(lb/event)* | Startup Train 2 Emission Rate *(lb/event)* | Emission Rate of Combined Trains [(4)] *(lb/event)* | Startup Events per Year *(events/yr)* | Worst Case Emission rate [(2)] *(lb/hr)* | Potential Emissions [(3)] *(tons/yr)* |
|---|---|---|---|---|---|---|---|
| $NO_X$ | 181 | 8 | 3 | 192 | 76 | 8.66 | 7.3 |
| $SO_2$ | 1 | 511 | 278 | 790 | | 815.2* | 30.0 |
| CO | 152 | 7 | 3 | 162 | | 7.44 | 6.2 |
| PM / $PM_{10}$ / $PM_{2.5}$ | 14 | 0.6 | 0.2 | 15 | | 0.66 | 0.6 |
| VOC | 10 | 0.4 | 0.2 | 11 | | 0.48 | 0.4 |

**Startup Emissions - Gasification ATM Vent**

| Pollutant | Gasification ATM Vent Startup Emission Rate (lb/Event) *(lb/event)* | Startup Events per Year *(events/yr)* | Worst Case Emission rate [(2)] *(lb/hr)* | Potential Emissions [(5)] *(tons/yr)* |
|---|---|---|---|---|
| $NO_X$ | 172 | 76 | 3.70 | 6.5 |
| $SO_2$ | 1 | | 0.03 | 0.04 |
| CO | 145 | | 3.20 | 5.5 |
| PM / $PM_{10}$ / $PM_{2.5}$ | 13 | | 0.30 | 0.5 |
| VOC | 9 | | 0.21 | 0.3 |

**Startup Emissions - Auxiliary Boiler Summary**

| Pollutant | Auxiliary Boiler Startup Emission Rate *(lb/event)* | Startup Events per Year *(events/yr)* | Worst Case Emission rate [(2)] *(lb/hr)* | Potential Emissions [(5)] *(tons/year)* |
|---|---|---|---|---|
| $NO_X$ | 2018 | 76 | 41.18 | 76.7 |
| $SO_2$ | 11 | | 0.18 | 0.4 |
| CO | 1211 | | 24.71 | 46.0 |
| PM / $PM_{10}$ / $PM_{2.5}$ | 110 | | 2.24 | 4.2 |
| VOC | 79 | | 1.62 | 3.0 |

**Methodology**
All emission rates are based on engineering estimates supplied by the vendor.
Startup Train 1: Startup Train 1 refers to the train which experiences a cold startup or hot startup depending on circumstances.
Startup Train 2: Startup Train 2 refers to the train which always experiences a hot startup, as a result of the combustion heat generated by Startup Train 1.
Elapsed time during a single startup (hrs) = 84 hours (5040 minutes)
Total amount of startup time (hrs/yr) = Startup Events per Year (events/yr) x Elapsed time during a single startup (hrs/event)
Total amount of startup time (hrs/yr) = 84 x 76 = 6384
(1) Emission Rate of Combined Trains (lb/event) = [Startup Train 1 Emission Rate (lb/event)] + [Startup Train 2 Emission Rate (lb/event)]
(2) Worst Case Emission Rate (lb/hr) = Worst Case Emission Rate during the startup event or during an equipment trip or malfunction.
Worst Case Emission rates have not been accounted for the Potential Emission Calculations, because these emissions occur for short period of time during the startup events. The purpose of worst case emission rate is to check its impact on hourly averages of Ambient Air Quality Standards.
(3) Potential Emission (tons/year) = [Emission Rate of Combined Trains (lb/event)] x [Startup Events per Year (events/year)] / [2000 (lb/ton)]
(4) Emission Rate of Combined Trains (lb/event) = [Emission Rate of Startup from Ambient (lb/event)] + [Startup Train 1 Emission Rate (lb/event)] + [Startup Train 2 Emission Rate (lb/event)]
(5) Potential Emission (tons/year) = [Startup Emission Rate (lb/event)] x [Startup Events per Year (events/year)] / [2000 (lb/ton)]
* Values represent an equipment trip or malfunction.

## Criteria Pollutant Emissions - Startup Mode

Startup Emissions - Combustion Turbine

| | Pollutant | Startup Train 1 Emission Rate (lb/event) | Startup Train 2 Emission Rate (lb/event) | Emission Rate of Combined Trains [1] (lb/event) | Startup Events per Year (events/yr) | Worst Case Emission Rate [2] (lb/hr) | Potential Emissions [3] (tons/yr) |
|---|---|---|---|---|---|---|---|
| **Cold Start, startup on natural gas, fuel transfer to Syngas, No SCR** | $NO_X$ | 3219 | 564 | 3783 | 76 | 290.66 | 143.8 |
| | $SO_2$ | 22 | 21 | 43 | | 14.28 | 1.6 |
| | $H_2SO4$ | 2 | 2 | 4 | | 1.35 | 0.2 |
| | CO | 6075 | 358 | 6433 | | 2091.45 | 244.5 |
| | $PM/PM_{10}/PM_{2.5}$ | 330 | 37 | 367 | | 20.84 | 13.9 |
| | VOC | 1185 | 63 | 1248 | | 503.00 | 47.4 |
| **Hot Start, startup on natural gas, fuel transfer to Syngas, No SCR** | $NO_X$ | 364 | 564 | 928 | 76 | 290.66 | 35.3 |
| | $SO_2$ | 8 | 21 | 29 | | 14.28 | 1.1 |
| | $H_2SO4$ | 1 | 2 | 3 | | 1.35 | 0.1 |
| | CO | 396 | 358 | 754 | | 2091.45 | 28.7 |
| | $PM/PM_{10}/PM_{2.5}$ | 37 | 37 | 74 | | 20.84 | 2.8 |
| | VOC | 71 | 63 | 134 | | 503.00 | 5.1 |
| **Cold Start, startup on natural gas, No SCR** | $NO_X$ | 306 | 203 | 509 | 20 | 290.66 | 5.1 |
| | $SO_2$ | 1 | 1 | 2 | | 14.28 | 0.0 |
| | $H_2SO4$ | 0 | 0 | 0 | | 1.35 | 0.0 |
| | CO | 4721 | 333 | 5054 | | 2091.45 | 50.5 |
| | $PM/PM_{10}/PM_{2.5}$ | 30 | 9 | 39 | | 20.84 | 0.4 |
| | VOC | 1090 | 34 | 1124 | | 503.00 | 11.2 |
| **Hot Start, startup on natural gas, No SCR** | $NO_X$ | 207 | 203 | 410 | 20 | 290.66 | 4.1 |
| | $SO_2$ | 1 | 1 | 2 | | 14.28 | 0.0 |
| | $H_2SO4$ | 0 | 0 | 0 | | 1.35 | 0.0 |
| | CO | 422 | 333 | 755 | | 2091.45 | 7.6 |
| | $PM/PM_{10}/PM_{2.5}$ | 10 | 9 | 19 | | 20.84 | 0.2 |
| | VOC | 35 | 34 | 69 | | 503.00 | 0.7 |
| **Worst Case Total for Cold or Hot Starts** | **$NO_X$** | | | | | | **143.8** |
| | **$SO_2$** | | | | | | **1.6** |
| | **$H_2SO4$** | | | | | | **0.2** |
| | **CO** | | | | | | **244.5** |
| | **$PM/PM_{10}/PM_{2.5}$** | | | | | | **13.9** |
| | **VOC** | | | | | | **47.4** |

**Methodology**

All emission rates are based on engineering estimates supplied by the vendor.

Startup Train 1: Startup Train 1 refers to the train which experiences a cold startup or hot startup depending on circumstances.

Startup Train 2: Startup Train 2 refers to the train which always experiences a hot startup, as a result of the combustion heat generated by Startup Train 1.

Elapsed time during a single startup (hours) = 84 hours (5040 minutes)

Total amount of startup time (hrs/yr) = Startup Events per Year (events/yr) x Elapsed time during a single startup (hrs/event)

Total amount of startup time (hrs/yr) = 84 x 76 = 6384

[1] Emission Rate of Combined Trains (lb/event) = [Startup Train 1 Emission Rate (lb/event)] + [Startup Train 2 Emission Rate (lb/event)]

[2] Worst Case Emission Rate (lb/hr) = Worst Case Emission Rate during the startup event or during an equipment trip or malfunction.

Worst Case Emission rates have not been accounted for the Potential Emission Calculations, because these emissions occur for short period of time during the startup events. The purpose of worst case emission rate is to check its impact on hourly averages of Ambient Air Quality Standards.

[3] Potential Emission (tons/year) = [Emission Rate of Combined Trains (lb/event)] x [Startup Events per Year (event/year)] / [2000 (lb/ton)]

## Criteria Pollutant Emissions - Shutdown Mode

### Shutdown Emissions - Combustion Turbine

| | Pollutant | Emission Rate of Combined Trains *(lb/event)* | Shutdown Events per Year *(events/year)* | Worst Case Emission Rate (1) *(lb/hr)* | Potential Emissions (2) *(tons/year)* |
|---|---|---|---|---|---|
| **Shutdown** | $NO_X$ | 247 | 76 | 338.30 | 9.39 |
| | $SO_2$ | 8 | | 57.80 | 0.30 |
| | $H_2SO4$ | 1 | | 6.40 | 0.04 |
| | CO | 165 | | 185.00 | 6.27 |
| | $PM/PM_{10}/PM_{2.5}$ | 11 | | 72.00 | 0.42 |
| | VOC | 29 | | 29.00 | 1.10 |
| **Shutdown After a Hot/Cold Start on natural gas** | $NO_X$ | 198 | 40 | – | 3.96 |
| | $SO_2$ | 1 | | – | 0.02 |
| | $H_2SO4$ | 0 | | – | 0.00 |
| | CO | 217 | | – | 4.34 |
| | $PM/PM_{10}/PM_{2.5}$ | 10 | | – | 0.20 |
| | VOC | 24 | | – | 0.48 |

### Shutdown Emissions - Thermal Oxidizer

| | Pollutant | Emission Rate of Combined Trains *(lb/event)* | Shutdown Events per Year *(events/yr)* | Worst Case Emission Rate (1) *(lb/hr)* | Potential Emissions (2) *(tons/yr)* |
|---|---|---|---|---|---|
| **Shutdown** | $NO_X$ | 16 | 76 | 3.20 | 0.61 |
| | $SO_2$ | 41 | | 10.20 | 1.56 |
| | CO | 13 | | 2.68 | 0.49 |
| | $PM/PM_{10}/PM_{2.5}$ | 1.2 | | 0.24 | 0.05 |
| | VOC | 0.9 | | 0.20 | 0.03 |

### Shutdown Emissions - Flare

| | Pollutant | Emission Rate of Combined Trains *(lb/event)* | Shutdown Events per Year *(events/yr)* | Worst Case Emission Rate (1) *(lb/hr)* | Potential Emissions (2) *(tons/yr)* |
|---|---|---|---|---|---|
| **Shutdown** | $NO_X$ | 162 | 76 | 76.65 | 6.16 |
| | $SO_2$ | 499 | | 219.60 | 18.96 |
| | CO | 664 | | 369.10 | 25.23 |
| | $PM/PM_{10}/PM_{2.5}$ | 3.60 | | 0.79 | 0.14 |
| | VOC | 2.60 | | 0.57 | 0.10 |

**Methodology**
All emission rates are based on engineering estimates supplied by the vendor.
Shutdown Event per Year = 76
Elapsed time during a single shutdown (hours) = 48 hours (2880 minutes)
Total amount of shutdown time (hrs/yr) = Shutdown Events per Year (events/yr) x Elapsed time during a single shutdown (hrs/event)
Total amount of shutdown time (hour) = 48 x 76 = 3648
(1) Worst Case Emission Rate (lb/hr) = Worst Case Emission Rate during the shutdown event or during an equipment trip or malfunction.
Worst Case Emission rates have not been accounted for the Potential Emission Calculations, because these emissions occur for short period of time during the startup events. The purpose of worst case emission rate is to check its impact on hourly averages of Ambient Air Quality Standards.
(2) Potential Total Emission (tons/year) = [Emission Rate of Combined Trains (lb/event)] x [Startup Events per Year (events/year)] / [2000 (lb/ton)]

## Hazardous Air Pollutant Emissions - Normal Operation

HAPs - Combustion Turbines (Natural Gas and Syngas Operations)

Number of Units = 2
Combined Maximum heat input of 2 units (MMBtu/hr) = 4218

| Emission Point ID # | |
|---|---|
| CTHRSG1 and 2 | S-2A and S-2B |

| Natural Gas Combustion | | |
|---|---|---|
| **Pollutant** | **Emission Factor** *lb/MMBtu* | **Combined Potential Emissions of 2 Units** *tons/yr* |
| Acetaldehyde | 4.0E-05 | 0.74 |
| Acrolein | 6.4E-06 | 0.12 |
| Benzene | 1.2E-05 | 0.22 |
| Ethylbenzene | 3.2E-05 | 0.59 |
| Formaldehyde | 3.2E-04 | 5.91 |
| Naphthalene | 1.3E-06 | 0.02 |
| Toluene | 1.3E-04 | 2.40 |
| Xylenes | 6.4E-05 | 1.18 |
| | **Total HAPs** | **11.19** |

| Syngas Combustion | | |
|---|---|---|
| **Pollutant** | **Emission Factor** *lb/MMBtu* | **Combined Potential Emissions of 2 Units** *tons/yr* |
| Arsenic | 7.9E-07 | 0.015 |
| Beryllium | 8.8E-08 | 0.002 |
| Cadmium | 1.1E-06 | 0.020 |
| Chromium | 5.1E-07 | 0.009 |
| Manganese | 5.3E-07 | 0.010 |
| Mercury | 1.9E-07 | 0.004 |
| Nickel | 5.7E-07 | 0.011 |
| Silica | 9.6E-06 | 0.177 |
| Selenium | 7.7E-07 | 0.014 |
| Zinc | 6.4E-07 | 0.012 |
| Lead | 2.0E-06 | 0.037 |
| | **Total HAPs** | **0.310** |

**Methodology**

Emission factors for natural gas combustion are from AP 42, Chapter 3: Stationary Internal Combustion Sources, Section 3.1: Stationary Gas Turbines, 4/00.

Emission factors for Syngas combustion are based on engineering estimates supplied by the vendor.

Hours of operation/yr = 8760

Potential Total Emission (tons/yr) = [Total Heat Input (MMBtu/hr) x Hours of Operation (hrs/yr)] / 2000 (lb/ton)

HAP emission estimates during startup and shutdown events are substantially less than normal operations.

## Hazardous Air Pollutant Emissions - Normal Operation
HAPs - Gasification Preheater, Turbine Gas Conditioning Pre-Heater, Flare and Thermal Oxidizer

| Emission Unit | Emission Point ID# | Number of Units | Hours of Operation | Combined Heat Input |
|---|---|---|---|---|
| | | | *hr/yr* | *MMBtu/hr* |
| Auxiliary Boiler | S-6 | 1 | 5000 | 300 |
| Gasification Preheater | S-5 | 2 | 8760 | 38.2 |
| Turbine Gas Conditioning Pre-Heater | S-5A and S-5B | 2 | 8760 | 10 |
| Flare | S-3 | 1 | 8760 | 2.67 |
| Thermal Oxidizer | S-4 | 1 | 8760 | 3.85 |
| | | | **Total Heat Input (MMBtu/hr) =** | **354.72** |

| Pollutant | Emission Factor | | Potential Emissions |
|---|---|---|---|
| | *lb/10^6 scf* | *lb/MMBtu* | *tons/yr* |
| 2-Methylnaphthalene | 2.4E-05 | 2.4E-08 | 1.88E-05 |
| 3-Methylchloranthrene | 1.8E-06 | 1.8E-09 | 1.41E-06 |
| 7,12-Dimethylbenz(a)anthracene | 1.6E-06 | 1.6E-09 | 1.25E-06 |
| Acenaphthene | 1.8E-06 | 1.8E-09 | 1.41E-06 |
| Acenaphthylene | 1.8E-06 | 1.8E-09 | 1.41E-06 |
| Anthracene | 2.4E-06 | 2.4E-09 | 1.88E-06 |
| Benz(a)anthracene | 1.8E-06 | 1.8E-09 | 1.41E-06 |
| Benzene | 2.1E-03 | 2.1E-06 | 1.64E-03 |
| Benzo(a)pyrene | 1.2E-06 | 1.2E-09 | 9.38E-07 |
| Benzo(b)fluoranthene | 1.8E-06 | 1.8E-09 | 1.41E-06 |
| Benzo(g,h,i)perylene | 1.2E-06 | 1.2E-09 | 9.38E-07 |
| Benzo(k)fluoranthene | 1.8E-06 | 1.8E-09 | 1.41E-06 |
| Chrysene | 1.8E-06 | 1.8E-09 | 1.41E-06 |
| Dibenzo(a,h)anthracene | 1.2E-06 | 1.2E-09 | 9.38E-07 |
| Dichlorobenzene | 1.2E-03 | 1.2E-06 | 9.38E-04 |
| Fluoranthene | 3.0E-06 | 2.9E-09 | 2.35E-06 |
| Fluorene | 2.8E-06 | 2.7E-09 | 2.19E-06 |
| Formaldehyde | 7.5E-02 | 7.4E-05 | 5.86E-02 |
| Hexane | 1.8E+00 | 1.8E-03 | 1.41E+00 |
| Indeno(1,2,3-cd)pyrene | 1.8E-06 | 1.8E-09 | 1.41E-06 |
| Naphthalene | 6.1E-04 | 6.0E-07 | 4.77E-04 |
| Phenanathrene | 1.7E-05 | 1.7E-08 | 1.33E-05 |
| Pyrene | 5.0E-06 | 4.9E-09 | 3.91E-06 |
| Tolune | 3.4E-03 | 3.3E-06 | 2.66E-03 |
| | | **Total HAPs** | **1.47** |

**Methodology**
Emissions are based on using 100% natural gas.
Emission Factors are from AP 42 , Chapter 1: External Combustion Sources, Section 1.4: Natural Gas Combustion, 7/98.
Pre-heaters are used only during startup of gasifier trains.
To convert from lb/$10^6$ scf to lb/MMBtu, divide by 1,020. [Reference: Footnote of Table 1.4-2 in AP 42]
Emission Factor (lb/MMBtu) = [Emission Factor (lb/$10^6$ scf)] /1020
Emission from Each Unit (tons/yr) = [Emission Factor (lb/MMBtu)] x [Heat Input (MMBtu/hr)] x [Hours of operation (hrs/yr)] / [2000 (lb/ton)]
Potential Emission (tons/yr) = Sum of emissions from the Gasification Preheater, Turbine Gas Conditioning Pre-Heater, Flare and Thermal Oxidizer

# Hazardous Air Pollutant Emissions - Normal Operation

## HAPs - Diesel Fired Emergency Generator

Number of Unit = 1
Rated Horse Power (hp) = 2200

| Emission Point ID # | |
|---|---|
| EMDSL | S-8 |

| Pollutant | Emission Factor | | | | Potential Emissions |
|---|---|---|---|---|---|
| | *lm/MMBtu* | *ng/J* | *ng/sec* | *g/hr* | *tons/yr* |
| Benzene | 7.8E-04 | 3.3E-01 | 5.4E+05 | 1.9E+00 | 1.1E-03 |
| Toluene | 2.8E-04 | 1.2E-01 | 2.0E+05 | 7.0E-01 | 3.9E-04 |
| Xylene | 1.9E-04 | 8.3E-02 | 1.3E+05 | 4.8E-01 | 2.7E-04 |
| Propylene | 2.8E-02 | 1.2E+01 | 1.9E+07 | 7.0E+01 | 3.9E-02 |
| Formaldehyde | 7.9E-05 | 3.4E-02 | 5.5E+04 | 2.0E-01 | 1.1E-04 |
| Acetaldehyde | 2.5E-05 | 1.1E-02 | 1.8E+04 | 6.3E-02 | 3.5E-05 |
| Acrolein | 7.9E-06 | 3.4E-03 | 5.5E+03 | 2.0E-02 | 1.1E-05 |
| Napthalene | 1.3E-04 | 5.6E-02 | 9.1E+04 | 3.3E-01 | 1.8E-04 |
| | | | | **Total HAPs** | **0.04** |

**Methodology**
Emission Factors are from AP 42 (Supplement B, 10/96), Table 3.4-3 and 3.4-4
Hours of operation/yr = 500
1 lb/MMBtu = 430 ng/J (Table 3.4-3, AP 42)
Emission Factor (ng/J) = [Emission Factor (lb/MMBtu)] x 430
Emission Factor (ng/sec) = [hp x 736 (J/sec) x Emission Factor (ng/J)]
Emission Factor (g/hr) = [Emission Factor (ng/sec)] x $10^{-9}$ (g/ng) x 3600 (sec/hr)]
Potential Total Emission (tons/yr) = [Emission Factor (g/hr) x 500 (hr/yr)] / [453.53 (lb/g) x 2000 (lb/ton)]

## HAPs - Diesel Fired Emergency Pump

Number of Unit = 1
Rated Horse Power (hp) = 420

| Emission Point ID # | |
|---|---|
| FIRPMP | S-8 |

| Pollutant | Emission Factor | | | | Potential Emissions |
|---|---|---|---|---|---|
| | *lm/MMBtu* | *ng/J* | *ng/sec* | *g/hr* | *tons/yr* |
| Benzene | 9.3E-04 | 4.0E-01 | 5.9E+05 | 2.1E+00 | 1.2E-03 |
| Toluene | 4.1E-04 | 1.8E-01 | 2.6E+05 | 9.3E-01 | 5.1E-04 |
| Xylene | 2.9E-04 | 1.2E-01 | 1.8E+05 | 6.5E-01 | 3.6E-04 |
| Propylene | 2.6E-03 | 1.1E+00 | 1.6E+06 | 5.9E+00 | 3.2E-03 |
| Formaldehyde | 1.2E-03 | 5.1E-01 | 7.5E+05 | 2.7E+00 | 1.5E-03 |
| Acetaldehyde | 7.7E-04 | 3.3E-01 | 4.9E+05 | 1.7E+00 | 9.6E-04 |
| Naphthalene | 8.5E-05 | 3.6E-02 | 5.4E+04 | 1.9E-01 | 1.1E-04 |
| | | | | **Total HAPs** | **0.0078** |

**Methodology**
Emission Factors are from AP 42 (Supplement B, 10/96), Table 3.3-2 and 3.3-3.
Hours of operation/yr = 500
Emission Factor (ng/J) = [Emission Factor (lb/MMBtu)] x 430
Emission Factor (ng/sec) = [hp x 736 (J/sec) x Emission Factor (ng/J)]
Potential Total Emission (tons/yr) = [Emission Factor (g/hr) x 500 (hr/yr)] / [453.53 (lb/g) x 2000 (lb/ton)]

## $NO_X$ and $SO_2$ Source-Wide Creditable Contemporaneous Emissions Decrease

(based Continuous Emission Monitoring System 'CEMS' data)

**Contemporaneous Period June 2002 - May 2004**

$NO_X$

| UNIT | Jun-02 | Jul-02 | Aug-02 | Sep-02 | Oct-02 | Nov-02 | Dec-02 | Jan-03 | Feb-03 | Mar-03 | Apr - 03 | May - 03 | Jun-03 | Jul-03 | Aug-03 | Sep-03 | Oct-03 | Nov-03 | Dec-03 | Jan-04 | Feb-04 | Mar-04 | Apr-04 | May-04 | Contemporaneous Emission Decrease (tons/yr) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **6-1** | 0.4 | 0 | 0 | 0.4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.4 |
| **7-1** | 89.7 | 75.6 | 111.4 | 41.6 | 35.8 | 23.2 | 42 | 0 | 15.8 | 124.3 | 134.4 | 53.2 | 56.2 | 139.2 | 115.7 | 67.5 | 0 | 0 | 41.5 | 97.1 | 135.5 | 151.4 | 140.5 | 62.8 | 877.2 |
| **7-2** | 64.1 | 118.4 | 109 | 21 | 33.2 | 19.2 | 43.9 | 0 | 2.2 | 33.7 | 105.9 | 51.2 | 42.8 | 87.8 | 131.9 | 23.1 | 0 | 0 | 59 | 124.6 | 141.1 | 140 | 114.1 | 33.3 | 749.8 |
| **8-1** | 61 | 100.6 | 72.3 | 47 | 36.6 | 27.1 | 50.9 | 0 | 15.5 | 81 | 79 | 30.2 | 51.7 | 104 | 69.7 | 60.5 | 0 | 0 | 63.1 | 98.8 | 136.9 | 144.3 | 135.8 | 47.2 | 756.6 |
| **Total Contemporaneous Emissions Decrease** (tons/yr) **=** | | | | | | | | | | | | | | | | | | | | | | | | | **2384.0** |

$SO_2$

| UNIT | Jun-02 | Jul-02 | Aug-02 | Sep-02 | Oct-02 | Nov-02 | Dec-02 | Jan-03 | Feb-03 | Mar-03 | Apr - 03 | May - 03 | Jun-03 | Jul-03 | Aug-03 | Sep-03 | Oct-03 | Nov-03 | Dec-03 | Jan-04 | Feb-04 | Mar-04 | Apr-04 | May-04 | Contemporaneous Emission Decrease (tons/yr) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **6-1** | 1 | 0 | 0 | 0.6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.8 |
| **7-1** | 317.9 | 263 | 416.9 | 232.1 | 188.8 | 144.8 | 236.9 | 0 | 86.9 | 585.8 | 497.8 | 189.1 | 194.7 | 599.9 | 527.4 | 239.7 | 0 | 0 | 152.9 | 375.6 | 509.9 | 512.5 | 570 | 300.2 | 3571.4 |
| **7-2** | 251.5 | 422.2 | 459.1 | 116.3 | 192.7 | 131.4 | 254.9 | 0 | 12.7 | 163.5 | 415.5 | 195.3 | 177 | 422.6 | 608.4 | 91.7 | 0 | 0 | 245.4 | 535 | 566.3 | 479 | 506.3 | 202.7 | 3224.75 |
| **8-1** | 261.1 | 430.6 | 350.8 | 277 | 208 | 207.8 | 291.6 | 0 | 89.8 | 424.7 | 370.5 | 121.3 | 195.8 | 528.2 | 358.3 | 273.5 | 0 | 0 | 252.6 | 399.8 | 596.6 | 514.7 | 594.3 | 257.3 | 3502.15 |
| **Total Contemporaneous Emissions Decrease** (tons/yr) **=** | | | | | | | | | | | | | | | | | | | | | | | | | **10299.1** |

**Methodology**

The following equipments are to be shutdown before IGCC starts operating.
Unit 6-1: Fuel oil-fired boiler
Unit 7-1: Pulverized coal fired boiler
Unit 7-2: Pulverized coal fired boiler
Unit 8-1 Pulverized coal fired boiler
Contemporaneous emission decrease due to shut down of a given unit (tons/yr) = [Sum of the emissions during June 2002 to May 2004 from a given emission unit] / 2
Source-wide creditable contemporaneous emission decrease (tons/yr) = Sum of the contemporaneous emissions decrease (tons/yr) due to shut down of given emission units (6-1, 7-1, 7-2

**VOC, CO, PM, $PM_{10}$ and $PM_{2.5}$ Source-Wide Creditable Contemporaneous emission Decrease**

(based on the amount of coal and oil burned during the contemporaneous period)

**Contemporaneous Period June 2002 - May 2004**

| Coal Usage Source-wide Creditable Contemporaneous Emission Decrease | | | | | |
|---|---|---|---|---|---|
| **Contemporaneous Period** | **Amount of Coal Burned** | **CO** | **VOC** | **PM** | **$PM_{10}/PM_{2.5}$** |
| *month* | *tons* | *ton/mo.* | *ton/mo.* | *ton/mo.* | *ton/mo.* |
| Jun-02 | 25490.69 | 6.37 | 0.76 | 19.17 | 4.41 |
| Jul-02 | 35223.34 | 8.81 | 1.06 | 26.49 | 6.09 |
| Aug-02 | 33202.54 | 8.30 | 1.00 | 24.97 | 5.74 |
| Sep-02 | 11894.61 | 2.97 | 0.36 | 8.94 | 2.06 |
| Oct-02 | 12354.79 | 3.09 | 0.37 | 9.29 | 2.14 |
| Nov-02 | 9311.51 | 2.33 | 0.28 | 7.00 | 1.61 |
| Dec-02 | 14278.57 | 3.57 | 0.43 | 10.74 | 2.47 |
| Jan-03 | 211.01 | 0.05 | 0.01 | 0.16 | 0.04 |
| Feb-03 | 4366.38 | 1.09 | 0.13 | 3.28 | 0.76 |
| Mar-03 | 28016.75 | 7.00 | 0.84 | 21.07 | 4.85 |
| Apr-03 | 40226.69 | 10.06 | 1.21 | 30.25 | 6.96 |
| May-03 | 18641.22 | 4.66 | 0.56 | 14.02 | 3.22 |
| Jun-03 | 19006.01 | 4.75 | 0.57 | 14.29 | 3.29 |
| Jul-03 | 41484.9 | 10.37 | 1.24 | 31.20 | 7.18 |
| Aug-03 | 42037.36 | 10.51 | 1.26 | 31.61 | 7.27 |
| Sep-03 | 17994.55 | 4.50 | 0.54 | 13.53 | 3.11 |
| Oct-03 | 0 | 0.00 | 0.00 | 0.00 | 0.00 |
| Nov-03 | 0 | 0.00 | 0.00 | 0.00 | 0.00 |
| Dec-03 | 17686.05 | 4.42 | 0.53 | 13.30 | 3.06 |
| Jan-04 | 36637.04 | 9.16 | 1.10 | 27.55 | 6.34 |
| Feb-04 | 42147.44 | 10.54 | 1.26 | 31.69 | 7.29 |
| Mar-04 | 43326.11 | 10.83 | 1.30 | 32.58 | 7.50 |
| Apr-04 | 41248.48 | 10.31 | 1.24 | 31.02 | 7.14 |
| May-04 | 16323.45 | 4.08 | 0.49 | 12.28 | 2.82 |

| Oil Usage Source-wide Creditable Contemporaneous Emission Decrease | | | | | |
|---|---|---|---|---|---|
| **Contemporaneous Period** | **Amount of Oil Burned** | **CO** | **VOC** | **PM** | **$PM_{10}/PM_{2.5}$** |
| *month* | *gallons* | *gal/mo.* | *gal/mo.* | *gal/mo.* | *gal/mo.* |
| Jun-02 | 37457 | 0.09 | 0.00 | 0.04 | 0.02 |
| Jul-02 | 6100 | 0.02 | 0.00 | 0.01 | 0.00 |
| Aug-02 | 50934 | 0.13 | 0.01 | 0.05 | 0.03 |
| Sep-02 | 10000 | 0.03 | 0.00 | 0.01 | 0.01 |
| Oct-02 | 8000 | 0.02 | 0.00 | 0.01 | 0.00 |
| Nov-02 | 17000 | 0.04 | 0.00 | 0.02 | 0.01 |
| Dec-02 | 10000 | 0.03 | 0.00 | 0.01 | 0.01 |
| Jan-03 | 0 | 0.00 | 0.00 | 0.00 | 0.00 |
| Feb-03 | 11000 | 0.03 | 0.00 | 0.01 | 0.01 |
| Mar-03 | 6000 | 0.02 | 0.00 | 0.01 | 0.00 |
| Apr-03 | 2000 | 0.01 | 0.00 | 0.00 | 0.00 |
| May-03 | 4000 | 0.01 | 0.00 | 0.00 | 0.00 |
| Jun-03 | 5000 | 0.01 | 0.00 | 0.01 | 0.00 |
| Jul-03 | 4000 | 0.01 | 0.00 | 0.00 | 0.00 |
| Aug-03 | 10000 | 0.03 | 0.00 | 0.01 | 0.01 |
| Sep-03 | 6000 | 0.02 | 0.00 | 0.01 | 0.00 |
| Oct-03 | 0 | 0.00 | 0.00 | 0.00 | 0.00 |
| Nov-03 | 0 | 0.00 | 0.00 | 0.00 | 0.00 |
| Dec-03 | 4 | 0.00 | 0.00 | 0.00 | 0.00 |
| Feb-04 | 1400 | 0.00 | 0.00 | 0.00 | 0.00 |
| Mar-04 | 1600 | 0.00 | 0.00 | 0.00 | 0.00 |
| Apr-04 | 1666 | 0.00 | 0.00 | 0.00 | 0.00 |
| May-04 | 0 | 0.00 | 0.00 | 0.00 | 0.00 |

| Total Source-wide creditable contemporaneous emission decreases (tons/yr) | | | | |
|---|---|---|---|---|
| | **CO** | **VOC** | **PM *** | **$PM_{10}/PM_{2.5}$ **** |
| **Total** (tons/yr) | **69.1** | **8.3** | **207.3** | **47.7** |

| | **CO** | **VOC** | **PM *** | **$PM_{10}/PM_{2.5}$ **** |
|---|---|---|---|---|
| **Coal Combustion Emission Factor** | 0.5 | 0.06 | 1.505 | 0.346** |
| **Oil Combustion Emission Factor** | 5 | 0.2 | 2 | 1 |

Emission Factors of coal combustion are from AP 42 (Update 9/98), Tables 1.1-4 and 1.1-3.
Emission Factors of oil combustion are from AP 42, Tables 1.3-1, 1.3-2, and 1.3-3, Supplement E
* PM Emission Factor = 10A x Efficiency of Control Equipment [Reference: Tables 1.1-4 in AP 42]
** PM10/PM2.5 Emission Factor = 2.3A x Efficiency of Control Equipment [Reference: Tables 1.1-4
Where: A = Average % Ash = 7.52 [Reference: Ash content value is provided by the source]
Efficiency of Control Equipment = 98% [Reference: Control Efficiency is provided by the source]

**Methodology**

The following equipments are to be shutdown before IGCC starts operating.

Unit 6-1: Fuel oil-fired boiler, Unit 7-1: Pulverized coal fired boiler, Unit 7-2: Pulverized coal fired boiler and Unit 8-1: Pulverized coal fired boiler

Source-wide creditable contemporaneous emission decrease is based on the amount of coal and oil burned during the contemporaneous period at the above listed emission units.

Contemporaneous emission decrease (tons/month) from coal combustion = [Coal Emission Factor (lb/ton)] x [Coal used (ton/month)] / [2000 (lb/ton)]

Contemporaneous emission decrease (tons/month) from oil combustion = [Oil Emission Factor (lb/kilo gallon of oil)] x [Oil Used (Kilo gallon/month)] / [2000 (lb/ton)]

Source-wide creditable Contemporaneous emission decrease (tons/yr) = Sum of the Contemporaneous emission decrease (tons/month) / 2

## Lead (Pb), Beryllium (Be), Hydrogen Fluoride ($H_2F$), Mercury (Hg) and Hydrogen Chloride (HCl)

### Source-Wide Creditable Contemporaneous Emission Decrease

(based on the amount of coal and oil burned during the contemporaneous period)

**Contemporaneous Period June 2002 - May 2004**

| **Source-wide Creditable Contemporaneous Emission Decrease** (tons/month) | | | | | | |
|---|---|---|---|---|---|---|
| **Contemporaneous Period** | **Amount of Coal Burned** | **Pb** | **Be** | **$H_2F$** | **Hg** | **HCl** |
| *month* | *tons* | *ton/mo.* | *ton/mo.* | *ton/mo.* | *ton/mo.* | *ton/mo.* |
| Jun-02 | 25490.69 | 0.01 | 0.00027 | 1.91 | 0.00 | 15.29 |
| Jul-02 | 35223.34 | 0.01 | 0.00037 | 2.64 | 0.00 | 21.13 |
| Aug-02 | 33202.54 | 0.01 | 0.00035 | 2.49 | 0.00 | 19.92 |
| Sep-02 | 11894.61 | 0.00 | 0.00012 | 0.89 | 0.00 | 7.14 |
| Oct-02 | 12354.79 | 0.00 | 0.00013 | 0.93 | 0.00 | 7.41 |
| Nov-02 | 9311.51 | 0.00 | 0.00010 | 0.70 | 0.00 | 5.59 |
| Dec-02 | 14278.57 | 0.00 | 0.00015 | 1.07 | 0.00 | 8.57 |
| Jan-03 | 211.01 | 0.00 | 0.00000 | 0.02 | 0.00 | 0.13 |
| Feb-03 | 4366.38 | 0.00 | 0.00005 | 0.33 | 0.00 | 2.62 |
| Mar-03 | 28016.75 | 0.01 | 0.00029 | 2.10 | 0.00 | 16.81 |
| Apr-03 | 40226.69 | 0.01 | 0.00042 | 3.02 | 0.00 | 24.14 |
| May-03 | 18641.22 | 0.00 | 0.00020 | 1.40 | 0.00 | 11.18 |
| Jun-03 | 19006.01 | 0.00 | 0.00020 | 1.43 | 0.00 | 11.40 |
| Jul-03 | 41484.9 | 0.01 | 0.00044 | 3.11 | 0.00 | 24.89 |
| Aug-03 | 42037.36 | 0.01 | 0.00044 | 3.15 | 0.00 | 25.22 |
| Sep-03 | 17994.55 | 0.00 | 0.00019 | 1.35 | 0.00 | 10.80 |
| Oct-03 | 0 | 0.00 | 0.00000 | 0.00 | 0.00 | 0.00 |
| Nov-03 | 0 | 0.00 | 0.00000 | 0.00 | 0.00 | 0.00 |
| Dec-03 | 17686.05 | 0.00 | 0.00019 | 1.33 | 0.00 | 10.61 |
| Jan-04 | 36637.04 | 0.01 | 0.00038 | 2.75 | 0.00 | 21.98 |
| Feb-04 | 42147.44 | 0.01 | 0.00044 | 3.16 | 0.00 | 25.29 |
| Mar-04 | 43326.11 | 0.01 | 0.00045 | 3.25 | 0.00 | 26.00 |
| Apr-04 | 41248.48 | 0.01 | 0.00043 | 3.09 | 0.00 | 24.75 |
| May-04 | 16323.45 | 0.00 | 0.00017 | 1.22 | 0.00 | 9.79 |

| **Total Source-wide Creditable Contemporaneous Emission Decrease** (tons/yr) | | | | | | |
|---|---|---|---|---|---|---|
| | **$H_2SO_4$*** | **Pb** | **Be** | **$H_2F$** | **Hg** | **HCl** |
| **Total** (tons/yr) | 515.00 | 0.0579 | 0.002893 | 20.67 | 0.011 | 165.33 |

* $H_2SO_4$ contemporaneous emission decrease (tons/yr) = 5% of $SO_2$ contemporaneous emission decrease
[Refrence: $H_2SO_4$ is assumed to be 5% of historical actual $SO_2$ emission rate]

$H_2SO_4$ emissions = 0.05 x 10299 (tons/yr) = 515 (tons/yr)

| | **Pb** | **Be** | **$H_2F$** | **Hg** | **HCl** |
|---|---|---|---|---|---|
| **Coal Combustion Emission Factors** (lb/ton) | 0.00042 | 0.000021 | 0.15 | 0.000083 | 1.2 |

Emissions factors are from AP 42 (9/98), Section 1.3 Fuel Oil Combustion, Table 1.3-11.

**Methodology**
The following equipments are to be shutdown before IGCC project.
Unit 6-1: Fuel oil-fired boiler
Unit 7-1: Pulverized coal fired boiler
Unit 7-2: Pulverized coal fired boiler
Unit 8-1 Pulverized coal fired boiler
Source-wide creditable contemporaneous emission decrease is based on the amount of coal burned during the contemporaneous period at the above listed emission units.

Source-wide creditable contemporaneous emission decrease (tons/yr) = Sum of the contemporaneous emission decrease (tons/month) / 2

## Netting Analyses - Normal Mode

### Criteria Air Pollutants

| Process / Emission Unit | CO tons/yr | $NO_X$ tons/yr | PM tons/yr | $PM_{10}$ tons/yr | $PM_{2.5}$ tons/yr | $SO_2$ tons/yr | VOC tons/yr | $H_2SO_4$ tons/yr |
|---|---|---|---|---|---|---|---|---|
| Paved Road Emissions | - | - | 16.07 | 3.14 | 0.47 | - | - | - |
| Dropping of Coal from conveyor onto Coal Pile | - | - | 3.48 | 1.64 | 0.25 | - | - | - |
| Unpaved Roads Emissions | - | - | 0.01 | 0.00 | 0.00 | - | - | - |
| Slag Loading on to Storage Pile | - | - | 0.39 | 0.18 | 0.03 | - | - | - |
| Wind Erosion | - | - | 10.18 | 5.09 | 0.76 | - | - | - |
| Dust Collection System for Coal Processing (Gasification) | - | - | 6.01 | 6.01 | 6.01 | - | - | - |
| Auxiliary Boiler | 61.76 | 102.94 | 5.59 | 5.59 | 5.59 | 0.55 | 4.04 | - |
| Flare Normal Operation (Natural Gas-Fired) | 0.96 | 1.15 | 0.09 | 0.09 | 0.09 | 0.007 | 0.06 | - |
| Thermal Oxidizer | 1.39 | 1.65 | 0.13 | 0.13 | 0.13 | 87.01 | 0.09 | - |
| Combustion Turbine Gas Conditioning Preheaters | 4.38 | 7.27 | 0.33 | 0.33 | 0.33 | 0.03 | 1.66 | - |
| Combined Cycle Combustion Turbine with HRSG | 832.15 | 1989.00 | 342.52 | 342.52 | 342.52 | 254.04 | 29.87 | 56.06 |
| Cooling Tower | - | - | 27.96 | 27.96 | 27.96 | - | - | - |
| Diesel Fired Emergency Fire Pump | 0.70 | 3.26 | 0.23 | 0.23 | 0.23 | 0.22 | 0.26 | - |
| Equipment Trip or Malfunction Events | 13.11 | 9.04 | 4.13 | 4.13 | 4.13 | 16.45 | 0.43 | - |
| Diesel Fired Emergency Generator | 3.03 | 7.15 | 0.10 | 0.08 | 0.07 | 0.22 | 0.39 | - |
| **Total Project Air Emission (Potential to Emit)** | **917.5** | **2121.5** | **417.2** | **397.1** | **388.6** | **358.5** | **36.8** | **56.1** |
| **Source-wide creditable contemporaneous emission decrease** | **69.1** | **2384.0** | **207.3** | **47.7** | **47.7** | **10299.1** | **8.3** | **515.0** |
| **Net Emission Increase** | **848.4** | **-262.5** | **209.9** | **349.4** | **340.8** | **-9940.6** | **28.5** | **-458.9** |
| **PSD Significant Emission Level** | **100** | **40** | **25** | **15** | **15** | **40** | **40** | **7** |
| **Net Emission Subject to PSD Review?** | **Yes** | **No** | **Yes** | **Yes** | **Yes** | **No** | **No** | **No** |

### Hazardous Air Pollutants (HAP)

| Process / Emission Unit | Lead (Pb) tons/yr | Mercury (Hg) tons/yr | Beryllium (Be) tons/yr | Fluoride (F) tons/yr | Single HAP tons/yr | Total HAPs tons/yr |
|---|---|---|---|---|---|---|
| Cooling Tower | - | - | - | - | - | - |
| Combustion Turbine Natural Gas Operation | - | - | - | - | 5.91 | 11.19 |
| Combustion Turbine on Syngas | 0.037 | 0.0036 | 0.001623 | - | 0.04 | 0.31 |
| Auxiliary Boiler, Gasification Preheater, Turbine Gas Conditioning Preheater, Flare and Thermal Oxidizer | - | | - | - | 1.41 | 1.47 |
| Diesel Fired Emergency Generator | - | | - | - | 0.04 | 0.04 |
| Diesel Fired Emergency Pump | - | - | - | - | 0.003 | 0.008 |
| **Total Project Air Emission (Potential to Emit)** | **0.04** | **0.0036** | **0.001623** | **0.00** | **7.40** | **13.02** |
| **Source-wide creditable contemporaneous emission decrease** | **0.06** | **0.0114** | **0.0029** | **20.67** | | |
| **Net Emission Increase** | **-0.021** | **-0.008** | **-0.001** | **-20.667** | | |
| **PSD Significant Emission Level** | **0.6** | **0.1** | **0.0004** | **3** | | |
| **Net Emission Subject to PSD Review?** | **No** | **No** | **No** | **No** | | |

**Methodology**
For a given pollutant, if the net emission is greater than the PSD significant emission level than that pollutant is subject to PSD review.
(     ) - Values within bracket indicates the amount by which the net emission decreases due to IGCC project.

## Netting Analyses - Startup and Shutdown Mode

### Criteria Air Pollutants

| Process / Emission Unit | CO | $NO_X$ | PM | $PM_{10}$ | $PM_{2.5}$ | $SO_2$ | VOC | $H_2SO_4$ |
|---|---|---|---|---|---|---|---|---|
| | *tons/yr* | *tons/yr* | *tons/yr* | *tons/yr* | *tons/yr* | *tons/yr* | *tons/yr* | *tons/yr* |
| Paved Road Emissions | - | - | 16.07 | 3.14 | 0.47 | - | - | - |
| Dropping of Coal from conveyor onto Coal Pile | - | - | 3.48 | 1.64 | 0.25 | - | - | - |
| Unpaved Roads Emissions | - | - | 0.01 | 0.00 | 0.00 | - | - | - |
| Slag Loading on to Storage Pile | - | - | 0.39 | 0.18 | 0.03 | - | - | - |
| Wind Erosion | - | - | 10.18 | 5.09 | 0.76 | - | - | - |
| Dust Collection System for Coal Processing (Gasification) | - | - | 6.01 | 6.01 | 6.01 | - | - | - |
| Gasification Preheater | 5.51 | 6.54 | 0.49 | 0.49 | 0.49 | 0.04 | 0.34 | - |
| Auxiliary Boiler | 61.76 | 102.94 | 5.59 | 5.59 | 5.59 | 0.55 | 4.04 | - |
| Combustion Turbine Gas Conditioning Preheaters | 4.38 | 7.27 | 0.33 | 0.33 | 0.33 | 0.03 | 1.66 | - |
| Cooling Tower | - | - | 27.96 | 27.96 | 27.96 | - | - | - |
| Diesel Fired Emergency Fire Pump | 0.70 | 3.26 | 0.23 | 0.23 | 0.23 | 0.22 | 0.26 | - |
| Equipment Trip or Malfunction Events | 13.11 | 9.04 | 4.13 | 4.13 | 4.13 | 16.45 | 0.43 | - |
| Diesel Fired Emergency Generator | 3.03 | 7.15 | 0.10 | 0.08 | 0.07 | 0.22 | 0.39 | - |
| Startup Emissions - Flare | 34.62 | 6.88 | 0.06 | 0.06 | 0.06 | 53.09 | 0.05 | - |
| Startup Emissions - Combustion Turbine | 244.50 | 143.80 | 13.90 | 13.90 | 13.90 | 1.60 | 47.40 | 0.20 |
| Startup Emissions - Thermal Oxidizer | 6.16 | 7.30 | 0.56 | 0.56 | 0.56 | 30.02 | 0.40 | - |
| Startup Emissions - Gasification ATM Vent | 5.51 | 6.54 | 0.49 | 0.49 | 0.49 | 0.04 | 0.34 | - |
| Startup Emissions - Auxiliary Boiler | 46.02 | 76.68 | 4.18 | 4.18 | 4.18 | 0.42 | 3.00 | - |
| Shutdown Emissions - Combustion Turbine | 10.61 | 13.35 | 0.62 | 0.62 | 0.62 | 0.04 | 1.58 | 0.04 |
| Shutdown Emissions - Thermal Oxidizer | 0.49 | 0.61 | 0.05 | 0.05 | 0.05 | 1.56 | 0.03 | - |
| Shutdown Emissions - Flare | 25.23 | 6.16 | 0.14 | 0.14 | 0.14 | 18.96 | 0.57 | - |
| **Total Project Air Emission (Potential to Emit)** | **461.63** | **397.50** | **94.95** | **74.87** | **66.31** | **123.23** | **60.51** | **0.24** |
| **Source-wide creditable contemporaneous emission decrease** | **69.1** | **2384.0** | **207.3** | **47.7** | **47.7** | **10299.1** | **8.3** | **515.0** |
| **Net Emission Increase** | **392.50** | **-1986.45** | **-112.36** | **27.15** | **18.59** | **-10175.87** | **52.24** | **-514.76** |
| **PSD Significant Emission Level** | **100** | **40** | **25** | **15** | **15** | **40** | **40** | **7** |
| **Net Emission Subject to PSD Review?** | **Yes** | **No** | **Yes** | **Yes** | **Yes** | **No** | **Yes** | **No** |

### Hazardous Air Pollutants (HAP)

| Process / Emission Unit | Lead (Pb) | Mercury (Hg) | Beryllium (Be) | Fluoride (F) | Single HAP | Total HAPs |
|---|---|---|---|---|---|---|
| | *tons/yr* | *tons/yr* | *tons/yr* | *tons/yr* | *tons/yr* | *tons/yr* |
| Cooling Tower | - | - | - | - | - | - |
| Combustion Turbine Natural Gas Operation | - | - | - | - | 5.91 | 11.19 |
| Combustion Turbine on Syngas | 0.037 | 0.0036 | 0.001623 | - | 0.04 | 0.31 |
| Auxiliary Boiler, Gasification Preheater, Turbine Gas Conditioning Preheater, Flare and Thermal Oxidizer | - | | - | - | 1.41 | 1.47 |
| Diesel Fired Emergency Generator | - | | - | - | 0.04 | 0.04 |
| Diesel Fired Emergency Pump | - | - | - | - | 0.003 | 0.008 |
| **Total Project Air Emission (Potential to Emit)** | **0.04** | **0.0036** | **0.001623** | **0.00** | **7.40** | **13.02** |
| **Source-wide creditable contemporaneous emission decrease** | **0.06** | **0.01** | **0.0029** | **20.67** | | |
| **Net Emission Increase** | **-0.02067** | **-0.00784** | **-0.00127** | **-20.67** | | |
| **PSD Significant Emission Level** | **0.6** | **0.1** | **0.0004** | **3** | | |
| **Net Emission Subject to PSD Review?** | **No** | **No** | **No** | **No** | | |

**Methodology**
Net Emission Increase = Total Project Air Emission - Source-wide Creditable Contemporaneous Emission Decrease
For a given pollutant, if the net emission is greater than the PSD significant emission level than that pollutant is subject to PSD review.
(    ) - Values within bracket indicates the amount by which the net emission decreases due to IGCC project.

# Indiana Department of Environmental Management
# Office of Air Quality

## Appendix B – BACT Analyses
## Technical Support Document (TSD)
## Prevention of Significant Deterioration (PSD)
## Significant Source Modification (SSM) of a Part 70 Source
## Significant Permit Modification (SPM) of Part 70 Operating Permit

### Source Background and Description

| | |
|---|---|
| Source Name: | Duke Energy Indiana – Edwardsport Generating Station |
| Source Location: | 15424 East State Road 358, Edwardsport, Indiana 47258 |
| County: | Knox |
| SIC Code: | 4911 |
| Operation Permit No.: | T 083-7243-00003 |
| Operation Permit Issuance Date: | August 10, 2004 |
| Significant Source Modification No.: | SSM 083-23529-00003 |
| Significant Permit Modification No.: | SPM 083-23531-00003 |
| Permit Reviewer: | Kimberly Cottrell |

### Proposed Modification

On August 18, 2006, the Office of Air Quality (OAQ) received an application from Duke Energy Indiana to construct and operate an Integrated Gasification and Combined Cycle (IGCC) electric generating plant at the Edwardsport generating station site, located at State Road 67, Edwardsport, Indiana, in Knox County. The IGCC plant would replace the existing electric generating equipment at the Edwardsport Generating Station. The Edwardsport Generating Station is classified as a major stationary source since the station is defined 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, and is located in an attainment or unclassified area as designated in 326 IAC 1-4 and that emits, or has the potential to emit, one hundred (100) tons per year or more of any regulated NSR pollutant (326 IAC 2-2-1(gg)(1).

The proposed IGCC project is considered a modification to an existing major stationary source and was evaluated under 326 IAC 2-2-2(d)(1) and (2) to determine whether or not the project triggers the Prevention of Significant Deterioration (PSD) requirements (326 IAC 2-2). This requires the project to be evaluated as to whether it causes both a significant emissions increase and a significant net emissions increase. Determination of the significant emission increase was based on the potential to emit from the IGCC project's emission sources. For the determination of a significant net emission increase, the emission increase consisting of potential emissions from the IGCC project's emission sources minus baseline actual emissions from equipment to be shutdown at the existing Edwardsport Generating Station was determined following the procedures in 326 IAC 2-2-2(d)(4). Based on that evaluation, the Edwardsport IGCC project is subject to 326 IAC 2-2 because, pursuant to 326 IAC 2-2-1(xx), the net emissions increase will equal or exceed the significant increase thresholds of one hundred (100) tons per year of carbon monoxide (CO), forty (40) tons per year of volatile organic compounds (VOC), twenty-five (25) tons per year of particulate matter (PM), and fifteen (15) tons per year of $PM_{10}$.

Because the Edwardsport IGCC project will result in a significant net emission increase for emissions of CO, VOC, and $PM/PM_{10}/PM_{2.5}$, the proposed project triggers the PSD requirements for these air pollutants as established in 326 IAC 2-2-2 and must meet the following requirements:

- 326 IAC 2-2-3 – Control Technology Review
- 326 IAC 2-2-4 – Air Quality Analysis
- 326 IAC 2-2-5 – Air Quality Impact
- 326 IAC 2-2-6 – Increment Consumption
- 326 IAC 2-2-7 – Additional Analysis
- 326 IAC 2-2-8(a) – Source Obligation
- 326 IAC 2-2-10 – Source Information
- 326 IAC 2-2-14 – Source Impacting Federal Class I Areas
- 326 IAC 2-2-15 – Public Participation

## Proposed New Emission Units

The proposed Integrated Gasification and Combined Cycle (IGCC) electric generating plant will consist of adding the following new emission units:

(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 & GASIF2, permitted in 2008. The gasifiers are not defined as emission units. However, the gasification preheaters designated as GPREHEAT1 and GPREHEAT2 will exhaust through Vent S-5a1 and S-5a2 during startup only.

(2) 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

(3) One natural gas fired 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.

(4) Two (2) natural gas fired gasification pre-heaters 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 Vent S-5a1 and S-5a2, respectively.

(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 & CTHRSG2, permitted in 2008, using diffusion combustors firing either syngas, natural gas, or combined syngas and natural gas, and nitrogen diluent injection when firing syngas, steam injection to control $NO_x$ when firing natural gas, and nitrogen diluent injection and steam injection when co-firing syngas and natural gas, and exhausting to Stacks S-2a and S-2b.

| Table 1: Nominal Heat Input Capacity (HHV) | |
|---|---|
| **Fuel** | **MMBtu/hr** |
| Syngas Only | 2098 |
| Natural Gas Only | 2094 |
| Combined Syngas and Natural Gas | 2129 |

Stacks S-2a and S-2b have continuous emissions monitors (CEMs) for 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, using a high-efficiency drift eliminator to control particulate emissions and exhausting to Stack S-9.

(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, 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.

(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.

(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.

## Emission Units to be Retired

The proposed expansion will consist of retiring the following emission units:

(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.

## Requirement for Best Available Control Technology (BACT)

326 IAC 2-2-2 and 326 IAC 2-2-3 require a Best Available Control Technology (BACT) review to be performed on the proposed IGCC Plant Project because the proposed project is considered a major modification to an existing major stationary source that will result in a significant net emissions increase for each of the following regulated air pollutants:

(1) Carbon monoxide (CO): significant net emission increase is greater than 100 tons per year;

(2) Particulate matter (PM): significant net emission increase is greater than 25 tons per year;

(3) Particulate matter with an aerodynamic diameter less than or equal to two and a half (2.5) micrometers ($PM_{2.5}$): significant net emission increase is greater than 15 tons per year;

(4) Particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers ($PM_{10}$): significant net emission increase is greater than 15 tons per year; and

(5) Volatile Organic Compound (VOC): significant net emission increase is greater than 40 tons per year.

326 IAC 8-1-6 requires new facilities which have potential emissions of 25 tons or more per year, located anywhere in the state, which are not otherwise regulated by 326 IAC 8, to reduce VOC emissions using Best Available Control Technology (State BACT). The requirements of 326 IAC 2-2-3 satisfy the requirements of 326 IAC 8-1-6.

See Appendix A – Emission Calculations – of this TSD for detailed Potential to Emit (PTE) calculations.

## Summary of the Best Available Control Technology (BACT) Process

BACT is an emission limitation based on the maximum degree of pollution reduction of emissions, which is determined to be achievable 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.

Federal guidance on BACT requires an evaluation that follows a "top down" process. In this approach, the applicant identifies the best-controlled similar source based on 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, innovative 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. Based on this, the OAQ will not evaluate or require any innovative controls for this BACT analysis. 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.

## Summary of Similar Sources (SIC Code 4911)

The table below summarizes existing sources with similar operations (IGCC Plants; SIC Code 4911) that are listed by the U.S. EPA and other permitting agencies websites.

**Table 2: Proposed and Existing IGCC Plants with SIC Code 4911**

| Company Name | Location | Capacity | Operating Status |
|---|---|---|---|
| Tampa Electric Company - Polk Power | Florida | 260 MW | Operating |
| Orlando Utilities Commission - Curtis H. Stanton Energy Center | Florida | 285 MW | Permit Issued – December 2006 |
| Christian County Generation, LLC – Taylorville Energy Center | Illinois | 677 MW | Permit Issued – June 2007 |
| Duke Energy Indiana – Wabash River Generating Station | Indiana | 262 MW | Operating |

Proposed IGCC projects that have not been permitted were eliminated from comparison in this review.

## 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 proposed expansion has

(1) Carbon monoxide (CO) potential to emit greater than 100 tons per year;

(2) Particulate matter (PM) potential to emit greater than 25 tons per year;

(3) Particulate matter with an aerodynamic diameter less than or equal to two and a half (2.5) micrometers ($PM_{2.5}$) potential to emit greater than 15 tons per year;

(4) Particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers ($PM_{10}$) potential to emit greater than 15 tons per year; and

(5) Volatile Organic Compound (VOC) potential to emit greater than 40 tons per year.

See Appendix A – Emission Calculations – of this TSD for detailed Potential to Emit (PTE) calculations.

## Requirement for PM/$PM_{2.5}$/$PM_{10}$ BACT

The following new emission units associated with the proposed IGCC plant at the Edwardsport Station have the potential to emit particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to two and a half (2.5) micrometers ($PM_{2.5}$), and particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers ($PM_{10}$); therefore, Best Available Control Technology analyses for PM / $PM_{2.5}$ / $PM_{10}$ were performed for the following units. For purposes of this BACT evaluation, any reference to particulate emissions includes PM, $PM_{10}$ and $PM_{2.5}$. $PM_{10}$ and $PM_{2.5}$ emissions are assumed to be equal to PM emissions.

(1) Two (2) combustion turbines, identified as CTHRSG1 and CTHRSG2, fired by syngas, natural gas, or combined syngas/natural gas.

(2) One (1) 300 MMBtu/hr natural gas-fired auxiliary boiler, identified as AUXBLR

(3) Two (2) natural gas-fired gasification pre-heater generation units, identified as GPREHEAT1 AND GPREHEAT2 and two (2) natural gas-fired turbine gas conditioning heaters, identified as TPREHEAT1 and TPREHEAT2,

(4) One (1) 2200 brake horsepower (Bhp) diesel-fired emergency generator, identified as EMDSL

(5) One (1) 420 brake horsepower (Bhp) diesel-fired emergency firewater pump, identified as FIRPMP

(6) One (1) flare with a 1.23 MMBtu/hr natural gas-fired pilot and 1.44 MMBtu/hr for sweep enrichment gas / flare purge gas, identified as FLR

(7) One (1) 3.85 MMBtu/hr natural gas-fired thermal oxidizer, identified as THRMOX

(8) One (1) induced draft cooling tower, identified as CT1-CT22

(9) Coal receiving and handling,

(10) Coal storage,

(11) Coal processing, and

(12) Paved roads.

**Particulate Matter (PM/ $PM_{10}$/ $PM_{2.5}$) BACT**

*Step 1: Identify Potential Control Technologies*

**<u>Control Technology:</u>**
Emissions of particulate matter are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, particulate emissions are controlled through one of the following mechanisms:

(1) Mechanical Collectors (such as Cyclones or Multiclones);

(2) Wet Scrubbers;

(3) Electrostatic Precipitators (ESP); and

(4) Fabric Filter Dust Collectors (Baghouses).

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.

**<u>Alternate Control Methods:</u>**
One or more alternate methods of control may be considered when more cost-effective than add-on controls or when add-on control technology may not be feasible. For the particulate emission sources at the proposed IGCC plant, the following alternate control methods were evaluated:

(1) Fuel Specifications – Clean Burning Fuel (*combustion turbines; auxiliary boiler*);

(2) Good Combustion Practices / Combustion Controls (*combustion turbines; auxiliary boiler; gasification preheaters, turbine gas conditioning heaters, flare, thermal oxidizer, emergency generator; emergency firewater pump*); and

(3) Low–Sulfur Fuel (*auxiliary boiler*); and

(4) Dissolved Solids Content (*cooling tower*); and

(5) Mist Eliminators (*cooling tower*);

(6) Wet Suppression (*coal handling*);

(7) Natural and artificial wind barriers, dust suppressants, re–vegetation, and watering (*coal storage*); and

(8) Street sweeping, minimization of track–out, removal of deposition on roads and maximum vehicle speed (*paved roads*).

*Steps 2 through 5 of the particulate BACT analyses are identified below for each emission unit associated with the proposed IGCC plant*

**Particulate Matter (PM/ $PM_{10}$/ $PM_{2.5}$) BACT – Combined Cycle Combustion Turbine – Syngas Combustion**

*Step 2: Eliminate Technically Infeasible Options*

The RACT/BACT/LAER (RBLC) Clearinghouse and review of other New Source Review (NSR) permits reveal that similar IGCC plants use fuel specifications and good combustion practices for controlling PM emissions from combustion turbines.

(a) **Add-on Control Technology:** Add on control devices such as fabric filters, electrostatic precipitators (ESPs), and scrubbers are not technically feasible for this industry because of the high operating temperatures, high volumes of airflow, fine particulate distribution, and very low PM emission rates. Based on availability and applicability, add-on control technology was eliminated from consideration due to technical infeasibility of practical use for combustion turbines.

(b) **Fuel Specifications – Clean Burning Fuel:** Clean burning fuels such as syngas and natural gas have a very low potential for generating PM. This technology is technically feasible and will be ranked for evaluation as BACT for controlling PM emissions from combustion turbines.

(c) **Good Combustion Practices / Combustion Controls:** Good combustion practices as well as operation and maintenance of the combustion turbines to keep them in good working order per the manufacturer's specifications will minimize PM emissions. The combustion turbine design includes diffusion combustion control systems that will also contribute to good combustion practice and further reduce PM emissions. This technology is technically feasible and will be ranked for evaluation as BACT for controlling PM emissions from combustion turbines.

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness*

The most effective method for control of PM emissions resulting from operation of combustion turbines at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices, and use of combustion controls inherent to the design of the combustion turbine.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 3 lists the proposed PM BACT determination along with the existing PM BACT determinations for combined cycle combustion turbines designed to burn syngas. All data in the table is based on the information obtained from the permit application submitted by Duke Energy Indiana, the U.S. EPA database of proposed gasification projects, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

(a) **Proposal**: Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The following has been proposed as BACT for PM emissions from each of the two proposed combined cycle combustion turbines, CTHRSG1 and CTHRSG2, when combusting syngas.

(1) Emission limitation of 0.019 pounds of combined $PM/PM_{10}/PM_{2.5}$ per million British thermal unit heat input (0.019 lbs/MMBtu). (Includes filterable and condensable particulate matter).

(2) Operation of the combined cycle combustion turbines using good combustion and operating practices.

(b) **Comparison with Other BACT Limitations**:
The BACT limitation for PM emissions from the proposed combined cycle combustion turbines, CTHRSG1 and CTHRSG2, is equal to or more stringent than the BACT limitation for PM emissions from similar combustion turbines used in support of other IGCC facilities when combusting syngas.

**<u>BACT limits based on lbs/MMBtu combustion turbine heat input.</u>**

(1) **Tampa Electric PPS, Mulberry, Florida** - Although the Tampa Electric Plant has a lower emission limit of 0.013 lbs/MMBtu, that limitation cannot be directly compared with the emission limit proposed by Duke Energy for the Edwardsport project. The emission limit for the Tampa Electric plant is based solely on filterable PM and does not apply to condensable PM, whereas the proposed emission limit for the Edwardsport plant is to apply to both filterable and condensable PM. Thus, the proposed limit for the Edwardsport plant is more stringent than the Tampa Electric facility limit.

(2) **Lima Energy IGCC, Lima, Ohio** - Although the Lima Energy IGCC Plant has a lower emission limit of 0.01 lbs/MMBtu, that limitation cannot be directly compared with the emission limit proposed by Duke Energy for the Edwardsport project. The emission limit for the Lima Energy IGCC plant is based on the combustion of petroleum coke and coal while the Edwardsport plant combusts only coal. In addition, the combustion turbine at the Lima Energy plant is different from the model at the Edwardsport plant. PM limits established for different turbine makes and models can not be compared directly.

(3) **Wabash River, Terre Haute, Indiana** - Although the Wabash River Plant has a lower emission limit of 0.005 lbs/MMBtu, that limitation cannot be directly compared with the emission limit proposed by Duke Energy for the Edwardsport project. The emission limit for the Wabash River plant has not been met by the facility. The lowest tested emissions were reported at 0.012 lb/MMBtu. In addition, this limit is based solely on filterable PM and does not apply to condensable PM, whereas the proposed emission limit for the Edwardsport plant is to apply to both filterable and condensable PM.

(4) **Taylorville Energy Center, Taylorville, Illinois -** The limit being proposed by Duke is more stringent than the most recent BACT determination made for the Taylorville Energy Center.

**BACT limits based on lbs/MMBtu gasifier heat input**

(1) **Tampa Electric PPS and Wabash River** – BACT limits can not be directly compared to the emission limit proposed by Duke Energy based on fuel type, turbine type and limit expressed with filterable particulates only.

(2) **Facilities with applications pending** – Since those facilities defined in Table 3 that have application pending have not been issued permits with specific PM emission limitations, the limits listed were not evaluated for comparison with the PM limit being proposed by Duke Energy.

**Table 3: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits – Combined Cycle Combustion Turbines (Syngas)**

| Facility | State | Application / Permit | Date | Plant Output *(MW)* | Gasifier Fuel | Gasifier Make | Combustion Turbine | BACT Limit *(lb/MMBtu Gasifier)* | BACT Limit *(lb/MMBtu Combustion Turbine)* | BACT Control Method | Limit Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Tampa Electric PPS | FL | Operating | 1996 | 250 | Petcoke / bit | GE (Texaco) | GE 7FA | 0.008 | 0.013 | Clean Fuel | F |
| Wabash River | IN | Operating | 1995 | 262 | Illinois bit | Conoco Phillips | F Class CTs | 0.001 | 0.005 ** | Clean Fuel | NA |
| OUC/Southern Stanton Unit B | FL | Final Permit | Dec-06 | 285 | PRB | KBR | GE 7FA (1) | 0.0149 | | Clean Fuel | NA |
| Taylorville Energy Center (Erora Gp) | IL | Final Permit | Jun-07 | 677 | Illinois bit | GE (Texaco) | GE 7FA (2) | 0.016 | 0.022 | Clean Fuel | F/B |
| Lima Energy IGCC (Global Energy) | OH | Final Permit | Mar-02 | 530 | Petcoke / coal | Conoco Phillips | GE 7FA (2) | 0.035 | 0.01 (F) | Clean Fuel | F/B |
| Southern Ill Clean Energy Ctr (Steelhead Energy) | IL | Application | Oct-04 | 544 | Illinois bit | Conoco Phillips | Not Available | 0.00924 | - | Clean Fuel | F |
| Excelsior Energy - Mesaba | MN | Application | Jun-06 | 531 | Petcoke / coal | Conoco Phillips | SW SGT6-5000F | 0.0088 | - | Clean Fuel | NA |
| American Electric Power Great Bend (AEP) | OH | Application | Sep-06 | 629 | Eastern bit | GE (Texaco) | GE 7FB (2) | 0.001 | - | Clean Fuel | F |
| Appalachian Power Mountaineer (AEP) | WV | Application | Sep-06 | 600 | Eastern bit | GE (Texaco) | GE 7FB (2) | 0.001* | - | Clean Fuel | F |
| Energy Northwest | WA | Application | Sep-06 | 600 | Petcoke / coal | Conoco Phillips | SW SGT6-5000F | 0.0087 | - | Clean Fuel | F/B |
| Nueces IGCC Plant (Tondu) | TX | Application | Sep-06 | 600 | Petcoke / coal | Shell | SW 501 F (2) | 0.0062 | - | Clean Fuel | F/B |
| Cash Creek Generation, LLC | KY | Application | Mar-07 | 630 | Coal | - | - | 0.0161 | 0.0217 | GCP | F/B |
| Tampa Electric Polk Unit 6 Project | FL | Application (Withdrawn) | Sep-07 | 230 | Petcoke / coal | | GE 7FB | 0.19 | - | | |
| | | | | | | Maximum (F/B) | | 0.035 | 0.022 | | |
| | | | | | | Minimum (F/B | | 0.0062 | 0.0217 | | |
| | | | | | | Average (F/B) | | 0.0164 | 0.0218 | | |

Notes:
F = limit based on filterable (front half) PM testing
F/B = limit based on filterable (front half) and condensable (back half) PM testing
NA = Not applicable
* This PM limit is being proposed as LAER
** Emission limit not met, highest tested emissions reported at 0.012 lb/MMBtu. Based on filterable PM only

**Table 3: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits – Combined Cycle Combustion Turbines (Syngas)**

| Facility | State | Application / Permit | Date | Plant Output *(MW)* | Gasifier Fuel | Gasifier Make | Combustion Turbine | BACT Limit *(lb/MMBtu Gasifier)* | BACT Limit *(lb/MMBtu Combustion Turbine)* | BACT Control Method | Limit Basis |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Proposed Edwardsport IGCC Plant | IN | Application - Under Review | Aug 06 | 630 | Coal | GE (Texaco) | GE 7FB | 0.013 | 0.019 | - | F/B |

(c) **New Source Performance Standards (40 CFR Part 60, Subpart Da)**
The following particulate emission limitations are the minimum standards for Electric Utility Steam Generating Units:

(A) 20 percent opacity (6-minute average) except for one 6-minute period per hour of no more than 27 percent opacity; and

(B) 0.015 lb/MMBtu (filterable portion); or

(C) 0.14 lb/MWh (filterable portion)

or

(A) 0.03 lb/MMBtu (filterable portion); and

(B) 0.1 percent of the combustion concentration determined according to the procedure in 40 CFR 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 fuel or solid-derived fuel; or

(C) 0.2 percent of the combustion concentration determined according to the procedure in 40 CFR 60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005, when combusting solid fuel or solid-derived fuel.

The proposed BACT for control of particulate matter from the two proposed combined cycle combustion turbines, CTHRSG 1 and CTHRSG 2, is more stringent than the emission limitations required by the applicable New Source Performance Standards for Electric Utility Steam Generating Units (40 CFR Part 60, Subpart Da).

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), the Permittee shall comply with the following requirements for particulate matter (PM / $PM_{10}$ / $PM_{2.5}$) for the two proposed combined cycle combustion turbines, CTHRSG1 and CTHRSG2 while combusting syngas:

(1) Each combined cycle combustion turbine, CTHRSG1 and CTHRSG2, shall be maintained in good working order and shall be operated using good combustion practices using diffusion combustor technology.

(2) The PM/$PM_{10}$/$PM_{2.5}$ emissions from each of the two proposed combined cycle combustion turbines, CTHRSG1 and CTHRSG2, shall not exceed 019 pounds per million British thermal units (lb/MMBtu) based on a 3-hour averaging period. This emission rate includes filterable and condensable particulate matter.

**Compliance Determination and Monitoring**

(1) Compliance with PM limits for syngas combustion will be based on initial compliance testing through stack testing based on NSPS requirements. This emission rate includes filterable and condensable particulate matter.

(2) Recordkeeping of fuel usage and turbine heat inputs.

(3) Emission estimates for $PM/PM_{10}/PM_{2.5}$ based on recorded heat input information and tested emission rate (lbs/MMBtu).

(4) CEM for $PM/PM_{10}/PM_{2.5}$ (lb/MWH only)

**Particulate Matter ($PM/ PM_{10}/ PM_{2.5}$) BACT – Combined Cycle Combustion Turbine – Natural Gas Combustion**

*Step 2: Eliminate Technically Infeasible Options*

The RACT/BACT/LAER (RBLC) Clearinghouse and review of other New Source Review (NSR) permits reveal that similar IGCC plants use fuel specifications and good combustion practices for controlling PM emissions from combustion turbines.

(a) **Add-on Control Technology:** Add on control devices such as fabric filters, electrostatic precipitators (ESPs), and scrubbers are not technically feasible for this industry because of the high operating temperatures, high volumes of airflow, fine particulate distribution, and very low PM emission rates.
Based on availability and applicability, add-on control technology was eliminated from consideration due to technical infeasibility of practical use for combustion turbines.

(b) **Fuel Specifications – Clean Burning Fuel:** Clean burning fuels such as natural gas have a very low potential for generating PM. This technology is technically feasible and will be ranked for evaluation as BACT for controlling PM emissions from combustion turbines.

(c) **Good Combustion Practices / Combustion Controls:** Good combustion practices as well as operation and maintenance of the combustion turbines to keep them in good working order per the manufacturer's specifications will minimize PM emissions. The combustion turbine design includes diffusion combustion control systems that will also contribute to good combustion practice and further reduce PM emissions.
This technology is technically feasible and will be ranked for evaluation as BACT for controlling PM emissions from combustion turbines.

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness*

The most effective method for control of PM emissions resulting from operation of combustion turbines at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices, and use of combustion controls inherent to the design of the combustion turbine.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Tables 3 and 4 list the proposed PM BACT determination along with the existing PM BACT determinations for combined cycle combustion turbines designed to burn natural gas. All data in the table is based on the information obtained from the permit application submitted by Duke Energy Indiana, the U.S. EPA database of proposed gasification projects, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

(a) **Proposal**: Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The following has been proposed as BACT for PM matter from each of the two proposed combined cycle combustion turbines, CTHRSG1 and CTHRSG2, when combusting natural gas.

(1) Emission limitation of 0.009 pounds of combined $PM/PM_{10}/PM_{2.5}$ per million British thermal unit heat input (0.009 lbs/MMBtu). (Includes filterable and condensable particulate matter).

(2) Operation of the combined cycle combustion turbines using good combustion and operating practices.

(b) **Comparison with Other BACT Limitations**:
The BACT limitation for PM emissions from the proposed combined cycle combustion turbines, CTHRSG1 and CTHRSG2, is equal to or more stringent than the BACT limitation for PM emissions from combustion turbines used in support of other IGCC facilities when combusting natural gas and taking into account filterable and condensable particulates. PM limits established for different turbine makes and models can not be compared directly.

**Table 4: Existing PM/$PM_{10}$/$PM_{2.5}$ BACT Limits – Combined Cycle Combustion Turbines (Natural Gas)**

| Facility | State | Application/ Permit | Date | Output *(MW)* | Gasifier Fuel | Gasifier Make | Combustion Turbine | BACT Limit *(lb/MMBtu)** | BACT Control Method | Limit Basis |
|---|---|---|---|---|---|---|---|---|---|---|
| Wabash River | IN | Operating | 1995 | 262 | Illinois bit | Conoco Phillips | F Class CTs | - | Clean Fuel | NA |
| OUC/Southern Stanton Unit B | FL | Final Permit | Dec-06 | 285 | PRB | KBR | GE 7FA (1) | - | Clean Fuel | NA |
| Taylorville Energy Center (Erora Gp) | IL | Final Permit | Jun-07 | 677 | Illinois bit | GE (Texaco) | GE 7FA (2) | 0.011** | Clean Fuel | F/B |
| Lima Energy IGCC (Global Energy) | OH | Final Permit | Mar-02 | 530 | Petcoke / coal | Conoco Phillips | GE 7FA (2) | 0.0097 | Clean Fuel | F |
| Southern Ill Clean Energy Ctr (Steelhead Energy) | IL | Application | Oct-04 | 544 | Illinois bit | Conoco Phillips | Not Available | 0.0047 | Clean Fuel | F |
| Excelsior Energy - Mesaba | MN | Application | Jun-06 | 531 | Petcoke / coal | Conoco Phillips | SW SGT6-5000F | 0.008 | Clean Fuel | NA |
| American Electric Power Great Bend (AEP) | OH | Application | Sep-06 | 629 | Eastern bit | GE (Texaco) | GE 7FB (2) | - | Clean Fuel | F |
| Appalachian Power Mountaineer (AEP) | WV | Application | Sep-06 | 600 | Eastern bit | GE (Texaco) | GE 7FB (2) | - | Clean Fuel | F |
| Energy Northwest | WA | Application | Sep-06 | 600 | Petcoke / coal | Conoco Phillips | SW SGT6-5000F | 0.0089 | Clean Fuel | F/B |
| Nueces IGCC Plant (Tondu) | TX | Application | Sep-06 | 600 | Petcoke / coal | Shell | SW 501 F (2) | 0.0074 | Clean Fuel | F/B |
| Calpine Corp | CA | - | May-06 | 300 | - | - | - | 0.0074 | Clean Fuel | NA |
| Forsyth Energy Projects, LLC | NC | - | Sep-05 | - | - | - | - | 0.019 | Clean Fuel | NA |
| Sierra Pacific Power Company | NV | - | Aug-05 | 306 | - | - | - | 0.011 | Clean Fuel | NA |
| Tampa Electric Polk Unit 6 Project | FL | Application (Withdrawn) | Sep-07 | 230 | Petcoke / coal | | GE 7FB | 0.015 | - | |
| | | | | | | | Maximum (F/B) | 0.011 | | |
| | | | | | | | Minimum (F/B) | 0.0074 | | |
| | | | | | | | Average (F/B) | 0.0091 | | |
| Proposed Edwardsport IGCC Plant | IN | Application - Under Review | Aug 06 | 630 | Coal | GE (Texaco) | GE 7FB | 0.009 | - | F/B |

Notes:
F = limit based on filterable (front half) PM testing
F/B = limit based on filterable (front half) and condensable (back half) PM testing
NA = Not applicable
* Based on heat input to combustion turbine
** This PM limit is being proposed as LAER

(c) **New Source Performance Standards (40 CFR Part 60, Subpart Da)**
The following particulate emission limitations are the minimum standards for Electric Utility Steam Generating Units:

(A) 20 percent opacity (6-minute average) except for one 6-minute period per hour of no more than 27 percent opacity; and

(B) 0.015 lb/MMBtu (filterable portion); or

(C) 0.14 lb/MWh (filterable portion)

or

(A) 0.03 lb/MMBtu (filterable portion); and

(B) 0.1 percent of the combustion concentration determined according to the procedure in 40 CFR 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 fuel or solid-derived fuel; or

(C) 0.2 percent of the combustion concentration determined according to the procedure in 40 CFR 60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005, when combusting solid fuel or solid-derived fuel.

The proposed BACT for control of particulate matter from the two proposed combined cycle combustion turbines, CTHRSG 1 and CTHRSG 2, is more stringent than the emission limitations required by the applicable New Source Performance Standards for Electric Utility Steam Generating Units (40 CFR Part 60, Subpart Da).

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), the Permittee shall comply with the following requirements for particulate matter (PM / $PM_{10}$ / $PM_{2.5}$) for the two proposed combined cycle combustion turbines, CTHRSG1 and CTHRSG2 while combusting natural gas:

(1) Each combined cycle combustion turbine, CTHRSG1 and CTHRSG2, shall be maintained in good working order and shall be operated using good combustion practices using diffusion combustor technology.

(2) The PM/$PM_{10}$/$PM_{2.5}$ emissions from each of the two proposed combined cycle combustion turbines, CTHRSG1 and CTHRSG2, shall not exceed 0.009 pounds per million British thermal units (lb/MMBtu)based on a 3-hour averaging period while combusting natural gas. This emission rate includes filterable and condensable particulate matter.

**Compliance Determination and Monitoring**

(1) Compliance with PM limits for natural gas combustion will be based on initial compliance testing through stack testing based on NSPS requirements.

(2) Recordkeeping of fuel usage and turbine heat inputs.

(3) Emission estimates for $PM/PM_{10}/PM_{2.5}$ based on recorded heat input information and tested emission factor (lbs/MMBtu)

(4) CEM for $PM/PM_{10}/PM_{2.5}$ (lb/MWH only)

**Particulate Matter ($PM/ PM_{10}/ PM_{2.5}$) BACT – Auxiliary Boiler**

*Step 2: Eliminate Technically Infeasible Options*

The RACT/BACT/LAER (RBLC) Clearinghouse and review of other New Source Review (NSR) permits reveal that similar boiler applications use fuel specifications, and good combustion practices for controlling PM emissions from the auxiliary boiler.

(a) **Add-on Control Technology:** Add on control devices such as fabric filters, electrostatic precipitators (ESPs), and scrubbers are not technically feasible for this industry because of the high operating temperatures, high volumes of airflow, fine PM distribution, and very low PM emission rates. Based on availability and applicability, add-on control technology was eliminated from consideration due to technical infeasibility for practical use for auxiliary boilers.

(b) **Fuel Specifications – Clean Burning Fuel/Low-Sulfur Fuel:** Clean burning fuels such as natural gas have a very low potential for generating PM. Natural gas typically has negligible sulfur content. This technology is technically feasible and will be ranked for evaluation as BACT for controlling PM emissions from auxiliary boilers.

(c) **Good Combustion Practices / Combustion Controls:** Good combustion practices as well as operation and maintenance of the auxiliary boiler to keep it in good working order per the manufacturer's specifications will minimize particulate emissions. This technology is technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from the auxiliary boiler.

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness*

The most effective method for control of particulate emissions resulting from operation of the auxiliary boiler at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices/combustion controls.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 5 lists the proposed particulate BACT determination along with the existing particulate BACT determinations for auxiliary boilers designed to burn natural gas. All data in the table is based on the information obtained from the permit application submitted by Duke Energy Indiana, the U.S. EPA database of proposed gasification projects, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

**Table 5: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits – Auxiliary Boiler**

| RBLC ID | Company | Permit Date | Heat Input *(MMBtu/hr)* | PM *(lbs/MMBtu)* |
|---|---|---|---|---|
| OH-0307 | Biomass Energy | 4/4/2006 | 247 | 0.007 |
| NV-0035 | Sierra Pacific Power Co. | 8/16/2005 | 159 | 0.004 |
| MD-0032 | Mirant Mid-Atlantic, LLC | 11/5/2004 | 60 | 0.01 |

**Table 5: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits – Auxiliary Boiler**

| RBLC ID | Company | Permit Date | Heat Input *(MMBtu/hr)* | PM *(lbs/MMBtu)* |
|---|---|---|---|---|
| OH-0269 | Biomass Energy | 1/5/2004 | 247 | 0.007 |
| TX-0469 | Texas Petrochemicals LP | 10/8/2003 | 332 | 0.008 |
| IA-0067 | Mid-American Energy Co. | 6/17/2003 | 429 | 0.0076 |
| NA | Taylorville Energy Center | 6/5/2007 | 279 | 0.007 |
| WV-0023 | Longview Power, LLC | 3/2/2004 | 225 | 0.0022 |
| SC-0071 | Columbia Energy Center | 7/3/2003 | 350 | 0.005 |
| NA | Tampa Electric Polk Unit 6 Project | 9/7/2007 | 230 | 0.007 |
| | | Maximum | 429 | 0.01 |
| | | Minimum | 60 | 0.0022 |
| | | Average | 248 | 0.0065 |
| Proposed Edwardsport IGCC Boiler | | - | 300 | 0.007 |

Note: All of the PM limits above were based on good combustion practices and the use of natural gas.

(a) **Proposal**: Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The following has been proposed as BACT for particulate matter from the auxiliary boiler:

(1) Maintenance of the boilers in good working order;

(2) Implementation of good combustion practices;

(3) Use of only natural gas; and

(4) Emission limitation of 0.007 pounds of combined PM / $PM_{10}$ / $PM_{2.5}$ per million British thermal unit heat input (0.007 lbs/MMBtu).

(b) **Comparison with Other Recent BACT Determinations**
In looking at other recent BACT determinations as provided in Table 5, the following critical items must be evaluated in order to establish the most stringent BACT limitation:

(1) Size of the boiler (MMBtu/hr); and

(2) Fuel to be combusted.

The PM limits for the facilities listed in Table 5 were all based on good combustion practices and the use of natural gas. The limit being proposed by Duke is based on AP-42 and is equivalent to the BACT limitations established for similar boilers rated at 300 MMBtu/hr. Data to determine how the lower limits were calculated for the other facilities was not readily available. There are no add-on control technologies that can be used on a natural gas fired boiler to control PM emissions.

(c) **New Source Performance Standards (40 CFR Part 60, Subpart Db)**
This Subpart does not impose a PM limit for natural gas-fired boilers.

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), the Permittee shall comply with the following requirements for particulate matter (PM / $PM_{10}$ / $PM_{2.5}$) for the auxiliary boiler:

(1) The auxiliary boiler shall be maintained in good working order and shall be operated using good combustion practices and the use of only natural gas.

(2) The PM / $PM_{10}$ / $PM_{2.5}$ emissions from the auxiliary boiler shall not exceed 0.007 pounds per million British thermal units (lb/MMBtu). This emission rate includes filterable and condensable particulate matter.

**Compliance Determination and Monitoring**

Maintain records of the amount of natural gas combusted (MMCF) during each month.

**Particulate Matter (PM/ $PM_{10}$/ $PM_{2.5}$) BACT – Natural Gas-Fired Gasification Pre-Heaters and Turbine Gas Conditioning Heaters**

*Step 2: Eliminate Technically Infeasible Options*

The RACT/BACT/LAER (RBLC) Clearinghouse and review of other New Source Review (NSR) permits reveal that similar natural gas-fired gasification pre-heaters and turbine gas conditioning heaters use fuel specifications and good combustion practices for controlling particulate matter emissions.

(a) **Add-on Control Technology:** Add on control devices such as fabric filters, electrostatic precipitators (ESPs), and scrubbers are not technically feasible for this industry because of the high operating temperatures, high volumes of airflow, fine particulate distribution, and very low particulate emission rates. Based on availability and applicability, add-on control technology was eliminated from consideration due to technical infeasibility for practical use for natural gas-fired gasification pre-heaters and turbine gas conditioning heaters.

(b) **Fuel Specifications – Clean Burning Fuel:** Clean burning fuels such as natural gas have a very low potential for generating particulates. This technology is technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from natural gas-fired gasification pre-heaters and turbine gas conditioning heaters.

(c) **Good Combustion Practices / Combustion Controls:** Good combustion practices as well as operation and maintenance of the gas-fired gasification pre-heaters to keep them in good working order per the manufacturer's specifications will minimize particulate emissions. This technology is technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from natural gas-fired gasification pre-heaters and turbine gas conditioning heaters.

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness*

The most effective method for control of particulate emissions resulting from operation of natural gas-fired gasification pre-heaters and turbine gas conditioning heaters at an IGCC plant is the use of fuel specifications that employ clean burning fuels and implementation of good combustion practices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 6 lists the proposed particulate BACT determination along with the existing particulate BACT determinations for small natural gas fired boilers/heaters. All data in the table is based on the information obtained from the permit application submitted by Duke Energy Indiana, the U.S. EPA database of proposed gasification projects, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

**Table 6: BACT Limits – PM/$PM_{10}$/$PM_{2.5}$ for Natural Gas Fired Boilers/Heaters <100 MMBtu/hr)**

| Facility Name | Permit ID | Permit Date | Equipment Type and Heat Input | PM Limits |
|---|---|---|---|---|
| WE Energies (WEPCO) - Port Washington Generating Station (WI) | 04-RV-175 | 10/13/2004 | Natural Gas Heater - 10.0 MMBtu/hr | 0.08 lbs/hr<br>0.008 lbs/MMBtu |
| Steelcorr Inc - Bluewater Project (AR) | 2062-AOP-R0 | 7/22/2004 | Natural Gas Boiler - 22 MMBtu/hr | 0.0076 lbs/MMBtu |
| Nucor Steel Corp - Nucor Steel Division (NE) | 35677RC3 | 6/22/2004 | Post Heater - 6.8 MMBtu/hr | -- |
| Ace Ethanol, LLC - Ace Ethanol - Stanley (WI) | 03-DCF-184 | 1/21/2004 | Natural Gas Boiler - 11.0 MMBtu/hr | 0.08 lbs/hr<br>0.0075 lbs/MMBtu |
| Interstate Power & Light - Emery Generating Station (IA) | 17-02-016 | 6/26/2003 | Natural Gas Heater - 9.0 MMBtu/hr | 0.29 tons/year<br>0.0075 lbs/MMBtu |
| Oglethorpe Power Corporation - Talbot Energy Facility (GA) | 4911-263-0013-P-03-0 | 6/9/2003 | Fuel Gas Preheaters - 5.0 MMBtu/hr | -- |
| Charter Manufacturing Co - Charter Steel | 13-04176 | 4/14/2003 | Natural Gas Boiler - 25 lbs/MMBtu | 0.19 lbs/hr<br>0.83 tons/year |
| COS-MAR Company - Styrene Monomer Plant (LA) | PSD-LA-690 | 2/11/2003 | Gas Heater - 14.4 lbs/MMBtu | 0.11 lbs/hr<br>0.01 lbs/MMBtu |
| Degussa Engineered Carbons, LP -Baytown Carbon Black Plant (TX) | PSD-1010 | 12/31/2002 | Back-Up Boiler - 13.4 lbs/MMBtu | 0.1 lbs/hr<br>0.44 tons/year |

(a) **Proposal**: Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The following has been proposed as BACT for particulate matter emitted from the natural gas-fired gasification pre-heaters and the natural gas-fired turbine gas conditioning heaters:

(1) Emission limitation of 0.0075 lbs/MMBtu of combined PM / $PM_{10}$ / $PM_{2.5}$) and maximum combined heat input of 38.2 MMBtu/hr for GPREHEAT1 and GPREHEAT2.

(2) Emission limitation of 0.0075 lbs/MMBtu of combined PM/$PM_{10}$/$PM_{2.5}$ and maximum combined heat input of 10.0 MMBtu/hr for TPREHEAT1 and TPREHEAT2.

(3) Good Combustion Practice and the use of only natural gas.

(b) **Comparison with Other BACT Limitations**
Table 6 presents BACT limits for PM/$PM_{10}$/$PM_{2.5}$ emissions from natural gas fired boilers/heaters <100 MMBtu/hr). The limit being proposed by Duke is equivalent to the BACT limitations established at these facilities. There are no add on pollution control devices that can be installed to control PM emissions from natural gas fired combustion devices.

(c) There are no applicable New Source Performance Standards.

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), the Permittee shall comply with the following requirements for particulate matter (PM / $PM_{10}$ / $PM_{2.5}$) for the natural gas-fired gasification pre-heaters and turbine gas conditioning heaters:

(1) The natural gas-fired gasification pre-heaters (maximum combined heat input of 38.2 MMBtu/hr) and turbine gas conditioning heaters (maximum combined heat input of 10.0 MMBtu/hr) shall be maintained in good working order and operated per manufacturer's specifications;

(2) Use of natural gas; and

(3) The PM / $PM_{10}$ / $PM_{2.5}$ emissions from the gas-fired gasification pre-heaters and turbine gas conditioning heaters shall not exceed 0.0075 lbs/MMBtu. This emission rate includes filterable and condensable particulate matter.

**Compliance Determination and Monitoring**

(1) Confirmation that pipeline quality natural gas is being combusted;

(2) Recordkeeping of natural gas usage; and

(3) Emission estimates based on recorded natural gas usage and AP-42 emission factors.

| **Particulate Matter (PM/ $PM_{10}$/ $PM_{2.5}$) BACT – Emergency Generator and Emergency Fire Pump** |
|---|

*Step 2: Eliminate Technically Infeasible Options*

The RACT/BACT/LAER (RBLC) Clearinghouse and review of other New Source Review (NSR) permits reveal that similar emergency generators and emergency fire pumps associated with recent power plant projects use good combustion practices for controlling particulate matter emissions, along with limited hours of operation because of their emergency/standby operating mode.

(a) **Add-on Control Technology:** Add on control devices such as fabric filters, electrostatic precipitators (ESPs), and scrubbers are not technically feasible for this industry because of the high operating temperatures, high volumes of airflow, fine particulate distribution, and very low particulate emission rates. Based on availability and applicability, add-on control technology was eliminated from consideration due to technical infeasibility for practical use for the emergency generator and the emergency fire pump.

(b) **Fuel Specifications – Clean Burning Fuel:** Clean burning fuels such as low-sulfur fuel oil have a low potential for generating particulates when being used in emergency/standby equipment. This technology is technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from emergency generators/fire pumps.

(c) **Good Combustion Practices:** Operations and maintenance of the emergency generators/fire pumps to keep them in good working order per the manufacturer's specifications will minimize particulate emissions. This technology is technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from the emergency generator and the emergency fire pump.

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness*

The most effective method for control of particulate emissions resulting from operation of the emergency generator and emergency fire pump at an IGCC plant is the implementation of good combustion practices, use of low-sulfur fuel oil or diesel fuel and limited hours of operation.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Information obtained from the permit application submitted by Duke Energy Indiana, the U.S. EPA database of proposed gasification projects, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies reveals that BACT for PM emissions from this type of emergency equipment is the use of low-sulfur fuel oil, limited hours of operation, compliance with NSPS IIII and good combustion and operating practices.

(a) **Proposal**: Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN BACT for particulate matter from the emergency generator and the emergency fire pump is proposed to be the use of low-sulfur diesel fuel and compliance with NSPS IIII. Good combustion/operating practices will also be implemented.

(b) **New Source Performance Standards (40 CFR Part 60, Subpart IIII)**
The following particulate emission limitations are the minimum standards for Stationary Compression Ignition Internal Combustion Engines.

(A) Emergency generators must meet the emission standards for nonroad CI engines in 40 CFR 60.4202.

(B) Emergency fire pumps must meet the applicable emission standards in Table 4 of Subpart IIII.

The proposed BACT for control of particulate matter from the emergency generator and fire pump is equivalent to the emission limitations required by the New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII).

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), the Permittee shall comply with the following requirements for particulate matter (PM / $PM_{10}$ / $PM_{2.5}$) for the proposed emergency generator and emergency fire pump:

(1) The emergency generator and emergency fire pump shall be maintained in good working order and shall operate per manufacturer's specifications.

(2) Meet the applicable emission limits imposed by NSPS Subpart IIII.

**Compliance Determination and Monitoring**

(1) Certification/plant documentation on meeting NSPS Subpart IIII emission limitations;

(2) Recordkeeping of fuel usage.

**Particulate Matter (PM/ $PM_{10}$/ $PM_{2.5}$) BACT – Flare Pilot and Gasification Startup**

A natural gas flare with a burner heat input of 1.23 MMBtu/hr will be used to combust syngas streams from various operations associated with the gasification process during startup, shutdown and trip events. An additional 1.44 MMBtu/hr will be required for sweep gas and flare gas purge. The BACT evaluation that follows addresses the control technology/techniques that could be used to control PM from the flare. The facts that both fuels combusted in the flare – natural gas in the pilot and excess syngas during startup and shutdown operations – are clean fuels, and relatively low volumes of fuel are combusted, contribute to projections of an insignificant level of emissions from this flare.

*Step 2: Eliminate Technically Infeasible Options*

The RACT/BACT/LAER (RBLC) Clearinghouse and review of other New Source Review (NSR) permits reveal that there is limited information on the use of gasification flares, The gasification flare associated with recent power plant projects use good combustion/operating practices for controlling particulate matter emissions.

(a) **Add-on Control Technology:** Add on control devices such as fabric filters, electrostatic precipitators (ESPs), and scrubbers are not technically feasible for this industry because of the high operating temperatures, high volumes of airflow, fine particulate distribution, and very low particulate emission rates. Based on availability and applicability, add-on control technology was eliminated from consideration due to technical infeasibility for practical use for the gasification flare.

(b) **Fuel Specifications – Clean Burning Fuel:** Clean burning fuels such as natural gas have a very low potential for generating particulates. This technology is technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from the gasification flare.

(c) **Good Combustion Practices:** Operations and maintenance of the flare to keep it in good working order per the manufacturer's specifications will minimize particulate emissions. This technology is technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from the gasification flare.

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness*

The most effective method for control of particulate emissions resulting from operation of the gasification flare at an IGCC plant is the maintenance of the equipment in good working order and operation per manufacturer’s specifications.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Information obtained from the permit application submitted by Duke Energy Indiana, the U.S. EPA database of proposed gasification projects, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies reveals that limited information is available on PM emissions from a flare that supports a gasification process. Information evaluated indicates that BACT for PM emissions form a gasification flare is the use of a natural gas-fired pilot burner and good combustion/operating practices.

(a) **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The following has been proposed as BACT for particulate matter from the gasification flare:

(1) The PM / $PM_{10}$ / $PM_{2.5}$ emissions from the gasification flare pilot shall not exceed 0.0075 lbs/MMBtu. This emission rate includes filterable and condensable particulate matter.

(2) Combustion of only natural gas in the flare pilot; and

(3) PM / $PM_{10}$ / $PM_{2.5}$ emissions from the gasification flare during startup shall not exceed one ton per year.

(b) **Comparison with Other BACT Limitations**
Based on review of Information on the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies, PM emissions from a flare that supports a gasification process are not specifically addressed in BACT analyses. Review of the Taylorville IGCC permit indicates that BACT for the gasification flare is the combustion of only natural gas in the flare pilot, operation of the flare pilot at all times, and good combustion practices.

(c) **New Source Performance Standards**
There are no established NSPS requirements that apply to PM emissions from gasification start-up events.

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), the Permittee shall comply with the following requirements for particulate matter (PM / $PM_{10}$ / $PM_{2.5}$) for the proposed gasification flare:

(1) The gasification flare shall be maintained in good working order and shall operate per manufacturer's specifications.

(2) The PM / $PM_{10}$ / $PM_{2.5}$ emissions from the gasification flare pilot shall not exceed 0.0075 lbs/MMBtu. This emission rate includes filterable and condensable particulate matter.

(3) Combustion of only natural gas in the flare pilot.

(4) PM / $PM_{10}$ / $PM_{2.5}$ emissions from the gasification flare during startup shall not exceed one ton per year.

**Compliance Determination and Monitoring**

(1) Operate with a flame present at all times when emissions are vented to the flare;

(2) Test volume flow rate to flare during startup event and confirm/certify heating value of volume flow rate.

(3) Within 10 days of initial startup of any unit in the gasification block, confirm flare is in compliance with 40 CFR 60.18. Permittee must maintain appropriate documentation to demonstrate that identified process operation gas streams are connected to the flare header.

(4) Record of amount of natural gas combusted (MMCF) during each month, continuous presence of flare pilot flame and no visual emissions.

(5) Continuous monitoring of gas flow rate to flame.

(6) Determine visual emissions by Reference Method 22.

(7) Record hours of startup events. Emission estimates based on hours of startup and pound per event emission factors.

**Particulate Matter (PM/ $PM_{10}$/ $PM_{2.5}$) BACT – Thermal Oxidizer Burner and Gasification Operations**

A natural gas thermal oxidizer with a burner heat input of 3.85 MMBtu/hr will be used to combust waste gas streams from the Sulfur Recovery Unit (SRU) sulfur pit vents and intermittent gas streams from the SRU associated with startup, shutdown and trip events. The BACT evaluation that follows addresses the control technology/technologies that could be used to control PM from the thermal oxidizer.

*Step 2: Eliminate Technically Infeasible Options*

The RACT/BACT/LAER (RBLC) Clearinghouse and review of other New Source Review (NSR) permits reveal that the gasification thermal oxidizer associated with recent power plant projects use good combustion practices for controlling particulate matter emissions.

(a) **Add-on Control Technology:** Add on control devices such as fabric filters, electrostatic precipitators (ESPs), and scrubbers are not technically feasible for this industry because of the high operating temperatures, high volumes of airflow, fine particulate distribution, and very low particulate emission rates. Based on availability and applicability, add-on control technology was eliminated from consideration due to technical infeasibility for practical use for the gasification thermal oxidizer.

(b) **Fuel Specifications – Clean Burning Fuel:** Clean burning fuels such as natural gas have a very low potential for generating particulates. This technology is technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from the gasification thermal oxidizer.

(c) **Good Combustion Practices:** Operations and maintenance of the equipment to keep it in good working order per the manufacturer's specifications will minimize particulate emissions. This technology is technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from the gasification thermal oxidizer.

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness*

The most effective method for control of particulate emissions resulting from operation of the gasification thermal oxidizer at an IGCC plant is the use of natural gas and the maintenance of the equipment in good working order and operation per manufacturer’s specifications.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

After review of Information obtained from the permit application submitted by Duke Energy Indiana, the U.S. EPA database of proposed gasification projects, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies, PM emissions from a thermal oxidizer that supports a gasification process are not specifically addressed in the BACT analyses. Information evaluated indicates that BACT for PM emissions from a gasification thermal oxidizer is the use of a natural gas-fired burner and good combustion/operating practices.

(a) **Proposal**: Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN The following has been proposed as BACT for particulate matter from the gasification thermal oxidizer:

(1) The PM / $PM_{10}$ / $PM_{2.5}$ emissions from the gasification thermal oxidizer burner shall not exceed 0.0075 lbs/MMBtu. This emission rate includes filterable and condensable particulate matter; and

(2) Combustion of only natural gas in the thermal oxidizer burner.

(3) PM / $PM_{10}$ / $PM_{2.5}$ emissions from the gasification thermal oxidizer shall not exceed one ton per year during startup operations.

(b) **Comparison with Other BACT Limitations**
Table 6 presents BACT limits for PM/$PM_{10}$/$PM_{2.5}$ emissions from natural gas fired boilers/heaters (<100 MMBtu/hr). The limit being proposed by Duke for the gasification thermal oxidizer is equivalent to the BACT limitations established at these facilities.

(c) **New Source Performance Standards**
There are no established NSPS requirements that apply to PM emissions from the gasification SRU and startup/shutdown events.

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), the Permittee shall comply with the following requirements for particulate matter (PM / $PM_{10}$ / $PM_{2.5}$) for the proposed thermal oxidizer:

(1) The gasification thermal oxidizer shall be maintained in good working order and shall operate per manufacturer's specifications.

(2) The gasification thermal oxidizer shall combust only natural gas.

(3) The PM / $PM_{10}$ / $PM_{2.5}$ emissions from the gasification thermal oxidizer burner shall not exceed 0.0075 lbs/MMBtu. This emission rate includes filterable and condensable particulate matter.

(4) PM / $PM_{10}$ / $PM_{2.5}$ emissions from the gasification thermal oxidizer shall not exceed one ton per year during startup operations.

**Compliance Determination and Monitoring**

(1) Operate at all times when an emission point vented to thermal oxidizer is in operation;

(2) Record amount of natural gas combusted (MMCF) during each month, date/time thermal oxidizer is not in operation;

(3) Maintain daily records of visible emission notations of stack exhaust shall be performed once per day during normal daylight operations; and

(4) Emission estimates based on recorded natural gas usage and AP-42 emission factors.

**Particulate Matter (PM/ $PM_{10}$/ $PM_{2.5}$) BACT – Cooling Tower**

*Step 2: Eliminate Technically Infeasible Options*

The RACT/BACT/LAER (RBLC) Clearinghouse and review of other New Source Review (NSR) permits reveal that the cooling tower associated with recent power plant projects use mist eliminators and to minimize the dissolved solid content in the water.

(a) **Add-on Control Technology:** Add on control devices such as a drift eliminator will minimize particulate emission rates. A drift eliminator is considered a passive control measure that acts to prevent pollutants from forming. This technology is technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from the cooling tower.

(b) **Good Operating Practices:** Operations and maintenance of the cooling tower fans and equipment to keep it in good working order per the manufacturer's specifications will minimize particulate emissions. This technology is technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from the cooling tower.

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness*

The most effective method for control of particulate emissions resulting from operation of the cooling tower at an IGCC plant is the use of drift eliminators to maintain a drift loss and the maintenance of the equipment in good working order and operation per manufacturer's specifications.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

The following table lists the proposed particulate BACT determination along with the existing particulate BACT determinations for the cooling tower. All data in the table is based on the information obtained from the permit application submitted by Duke Energy Indiana, the U.S. EPA database of proposed gasification projects, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

**Table 7: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits – Cooling Tower**

| Company Name / Operation | $PM / PM_{10} / PM_{2.5}$ Limit | Control Technology & Compliance Methods |
|---|---|---|
| **PROPOSAL** | | |
| Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN (Proposed permit 23529) Cooling Tower | $PM / PM_{10} / PM_{2.5}$ 6.4 lbs/hr | Drift loss rate of 0.001% or less<br>Use of drift eliminator<br>Maintenance of fans and equipment in good working order.<br>Operation per manufacturer's specifications |
| **COMPARABLE BACT DETERMINATIONS (List in Top-Down Order by Control Efficiency)** | | |
| Western Greenbrier Co-Generation, LLC - | 0.79 lb/hr | Drift eliminators @ 0.0005% drift rate |
| Forsyth Energy Projects, LLC. - | *0.002 lb/hr -3 hr average* | - |
| Golden Grain Energy - | *1.33 lb/hr – 3 hr average* | Mist eliminator |
| Diamond Wanapa I, L.P. - | 3532.0 ppm solids in mist | High efficiency 0.0005% drift eliminators<br>TDS in water less than 3.532 ppmv |
| Arizona Clean Fuels Yuma, LLC. - | *1.6 lbs/hr* | High efficiency drift eliminators |

(a) **Proposal**: Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The proposed BACT emission limitations for particulate matter from the cooling tower is of 6.4 lbs/hr of combined $PM / PM_{10} / PM_{2.5}$.

(b) **Comparison with other BACT Limitations:**
A drift loss rate of 0.0005% or less is being proposed as BACT for the proposed cooling tower. This limit is equivalent to the BACT limitations established for the cooling towers at other facilities.

(c) **New Source Performance Standards**
There are no established NSPS requirements that apply to PM emissions from the proposed cooling tower.

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), the Permittee shall comply with the following requirements for particulate matter ($PM / PM_{10} / PM_{2.5}$) for the proposed cooling tower:

(1) The use of high efficiency drift eliminator

(2) Maintenance of the fans and equipment in good working order and shall operate per manufacturer's specifications.

(3) Drift loss rate of less than 0.0005% of the recirculating water flow

(4) The $PM / PM_{10} / PM_{2.5}$ emissions from the cooling tower shall not exceed 6.4 lbs/hr. This emission rate includes filterable and condensable particulate matter.

(5) Total Dissolved Solid (TSD) load of ≤ 5,000 mg/L.

**Compliance Determination and Monitoring**

(1) Documentation that confirms mist eliminator efficiency of 0.0005%

(2) Documentation that confirms Total Dissolved Solid loading of no more than 5,000 ppm

**Particulate Matter (PM/ $PM_{10}$/ $PM_{2.5}$) BACT – Coal Receiving, Transferring, Handling, and Preparation for Gasification**

*Step 2: Eliminate Technically Infeasible Options*

The RACT/BACT/LAER (RBLC) Clearinghouse and review of other New Source Review (NSR) permits reveal that the coal receiving, transferring, handling and preparation for gasification associated with recent power plant projects use baghouse and wet suppression to minimize particulate emissions.

**<u>Add-on Control Technology:</u>**
Add on control devices such as a baghouse or wet suppression will minimize particulate emission rates. A baghouse is an air pollution abatement device used to trap particulates by filtering gas streams through large fabric bags. Baghouses typically achieve PM control efficiencies of greater than 99%

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

These technologies are technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from the coal receiving and handling. Therefore, there is no elimination of technically infeasible fugitive PM control alternatives.

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness*

Baghouse control of coal unloading operations achieves a control efficiency of greater than 99% versus the wet suppression control efficiency of 50-70%. Thus, the use of a baghouse is the top ranked control alternative for control of coal unloading, transferring, handling and gasification preparation operations.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 8 lists the proposed particulate BACT determination, along with the existing particulate BACT determinations, for coal receiving and handling and coal transferring. All data in the table is based on the information obtained from the permit application submitted by Duke Energy Indiana, the U.S. EPA database of proposed gasification projects, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

(a) **Proposal**: Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN

The following has been proposed as BACT for particulate matter from coal receiving, handling and transferring:

(1) Best management practices (including closed conveyance systems);

(2) High efficiency baghouse with documented PM outlet loading of 0.003 grains per dry standard cubic foot; and

(3) Partial Enclosure of coal receiving operation.

(b) **Comparison with other BACT Limitations**:
Table 8 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 8: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits - Coal Receiving, Transferring and Handling**

| Facility | State | Application/ Permit | Date | BACT Limit | BACT Control Method |
|---|---|---|---|---|---|
| Homeland Energy Solutions, LLC | IA | Draft | 08/28/07 | - $PM/PM_{10}$ – 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 |
| Western Farmers Electric Coop | OK | | 02/09/07 | $PM/PM_{10}$ – 0.01 gr/dscf | Fabric filter baghouse |
| Cutler-Magner Company | WI | | 08/16/06 | PM– 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 | PM – 0.01 gr/dscf | Fabric filter |
| Lamar Utilities Board DBA Lamar Light and Power | CO | | 02/03/06 | $PM_{10}$ - 0.02 lb/ton | High efficiency fabric filter baghouse (99.5%) |
| Public Service Company of Colorado | CO | | 070/5/05 | $PM/PM_{10}$ – 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 |
| Red Tail Energy, LLC | ND | | 08/04/04 | $PM/PM_{10}$ – 0.004 gr/dscf | 99.8% reduction and use of baghouse |

**Table 8: Existing PM/$PM_{10}$/$PM_{2.5}$ BACT Limits - Coal Receiving, Transferring and Handling**

| Facility | State | Application/ Permit | Date | BACT Limit | BACT Control Method |
|---|---|---|---|---|---|
| Taylorville Energy Center – Illinois (05040027 – 6/15/2007) | IL | | 06/15/07 | PM/$PM_{10}$ – 0.01 gr/dscf 0.84 tons/year (handling and storage). | Use of enclosure and use of fabric filter or baghouse if necessary. |
| Notes: | | Maximum (gr/dscf) | | 0.01 | |
| | | Minimum (gr/dscf) | | 0.004 | |
| | | Average (gr/dscf) | | 0.0074 | |
| Proposed Edwardsport IGCC Plant | IN | Application - Under Review | Aug 06 | 0.003 gr/dscf | - |

(c) **New Source Performance Standards**
There are no established NSPS requirements that apply to PM emissions from the proposed coal handling operations.

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), the Permittee shall comply with the following requirements for particulate matter (PM / $PM_{10}$ / $PM_{2.5}$) for the proposed coal receiving, transferring and handling:

(1) Best management practices (including closed conveyance systems and partial enclosure of coal receiving operation); and

(2) High efficiency baghouse with grain loading of 0.003 gr/dscf and emission rate of 0.34 lbs/hr for coal receiving and preparation for gasification.

**Compliance Determination and Monitoring**

(1) Baghouses shall be in operation and control emissions at all times;

(2) Stack testing of each baghouse following EPA testing procedures; and

(3) Visible emission notations shall be performed once per week during normal daylight operations, record the pressure drop across each baghouse.

**Particulate Matter (PM/ $PM_{10}$/ $PM_{2.5}$) BACT – Lime Receiving, Transferring, Handling**

*Step 2: Eliminate Technically Infeasible Options*

The RACT/BACT/LAER (RBLC) Clearinghouse and review of other New Source Review (NSR) permits reveal that the lime receiving, transferring, and handling associated with recent power plant projects use baghouse and wet suppression to minimize particulate emissions.

**Add-on Control Technology:**
Add on control devices such as a baghouse or wet suppression will minimize particulate emission rates. A baghouse is an air pollution abatement device used to trap particulates by filtering gas streams through large fabric bags. Baghouses typically achieve PM control efficiencies of greater than 99%

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%.

These technologies are technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from the lime receiving and handling. Therefore, there is no elimination of technically infeasible fugitive PM control alternatives.

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness*

Baghouse control of lime unloading operations achieves a control efficiency of greater than 99% versus the wet suppression control efficiency of 50-70%. Thus, the use of a baghouse is the top ranked control alternative for control of lime unloading, transferring, and handling.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 9 lists the proposed particulate BACT determination, along with the existing particulate BACT determinations, for lime receiving and handling. All data in the table is based on the information obtained from the permit application submitted by Duke Energy Indiana, the U.S. EPA database of proposed gasification projects, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

**Table 9: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits - Lime Handling**

| Facility | State | Application/ Permit | Date | BACT Limit* | BACT Control Method |
|---|---|---|---|---|---|
| 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 |
| 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%) |

**Table 9: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits - Lime Handling**

| Facility | State | Application/ Permit | Date | BACT Limit* | BACT Control Method |
|---|---|---|---|---|---|
| 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 Lime Company - *Based on several processes | AL | | 03/23/05 | PM – 0.005 gf/dscf, 0.009 gr/dscf or 0.0114 gr/dscf (calculated) | |
| Notes: | | Maximum (gr/dscf) | | 0.01 | |
| | | Minimum (gr/dscf) | | 0.005 | |
| | | Average (gr/dscf) | | 0.009 | |
| Proposed Edwardsport IGCC Plant | IN | Application - Under Review | Aug 06 | 0.003 gr/dscf | - |

(a) **Proposal**: Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The following has been proposed as BACT for particulate matter from lime receiving, handling and transferring:

(1) Best management practices; and

(2) High efficiency baghouse with documented PM outlet concentration of 0.003 grains per dry standard cubic foot.

(b) **Comparison with other BACT Limitations:**
Table 9 presents BACT limits for $PM/PM_{10}/PM_{2.5}$ emissions from lime 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 lime handling operations.

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), the Permittee shall employ a high efficiency baghouse with documented PM grain loading of 0.003 gr/dscf and emission rate of 0.34 lbs/hr for particulate matter ($PM$ / $PM_{10}$ / $PM_{2.5}$) for the proposed lime receiving, transferring and handling operation:

**Compliance Determination and Monitoring**

(1) Baghouses shall be in operation and control emissions at all times;

(2) Stack testing of baghouse following EPA testing procedures; and

(3) Visible emission notations shall be performed once per week during normal daylight operations, record the pressure drop across the baghouse.

**Particulate Matter (PM/ $PM_{10}$/ $PM_{2.5}$) BACT – Coal and Slag Storage**

*Step 2: Eliminate Technically Infeasible Options*

The RACT/BACT/LAER (RBLC) Clearinghouse and review of other New Source Review (NSR) permits reveal that the coal storage associated with recent power plant projects use dust suppressants, partial/total enclosure, adjustable feeders and drop systems, and compaction with particulate emission reductions ranging from 90-95%. Presented below are potential controls of PM emissions from storage piles obtained from the WRAP Document.

**Table 10: PM Control Methods for Storage Piles)**

| SOURCE | CONTROL METHOD | % CONTROL |
|---|---|---|
| Storage Piles | • Plant trees or shrubs as a windbreak<br>• Create cross-wind ridges<br>• Erect artificial wind barriers<br>• Apply dust suppressant or gravel<br>• Revegetate; apply cover crop<br>• Water exposed area before high winds | • 25%<br>• 24 – 93%<br>• 4 – 88%<br>• 84%<br>• 90%<br>• 90% |

**Add-on Control Technology:**
Add on control devices such as wet suppression will minimize particulate emission rates.

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. Duke will also be utilizing coal compaction techniques to further control PM emissions.

This technology is technically feasible and will be ranked for evaluation as BACT for controlling particulate emissions from coal and slag storage.

**Additional Controls:**
Partial enclosures are technically infeasible due to the large sizes of the active and inactive storage piles (>50,000 $m^2$). Enclosures would also create a major obstacle to equipment requiring access to the individual piles.

Although creating cross-wind ridges could potentially achieve 93% control, the midpoint of this range would have been applied to be conservative. Subsequently, cross wind ridges were excluded from further review since the techniques proposed should be more reliable based on prior experience.

These technologies are technically infeasible due to engineering or economic constraints and will not be further evaluated as BACT for controlling particulate emissions from the coal storage.

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness*

The only effective control technology for controlling PM emissions from a coal or slag storage pile is the use of suppressants and development of a fugitive dust plan and good management practices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Tables 11 and 12 list the proposed particulate BACT determination, along with the existing particulate BACT determinations for the coal and slag storage piles. All data in the table is based on the information obtained from the permit application submitted by Duke Energy Indiana, the U.S. EPA database of proposed gasification projects, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

(a) **Proposal**: Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The following has been proposed as BACT for particulate matter from coal and slag storage piles:

(1) Best management practices (including coal compaction); and

(2) Fugitive dust control plan including wet suppression as required by site conditions.

(b) **Comparison with other BACT Limitations:**
Tables 11 and 12 present BACT limits for $PM/PM_{10}/PM_{2.5}$ emissions from coal and slag storage piles. The limit being proposed by Duke is equivalent to the BACT limitations established for coal and slag storage piles at these facilities.

**Table 11: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits - Slag Storage Piles**

| Facility | State | Application / Permit | Date | BACT Limit | BACT Control Method |
|---|---|---|---|---|---|
| University of Northern Iowa – Cola Pile Receiving and Reclaim | IA | | 05/05/07 | $PM/PM_{10}$ – 95% reduction | Use of dust suppressants |

**Table 11: Existing PM/$PM_{10}$/$PM_{2.5}$ BACT Limits - Slag Storage Piles**

| Facility | State | Application / Permit | Date | BACT Limit | BACT Control Method |
|---|---|---|---|---|---|
| NRG Texas –Active Storage Pile (3) and Active Storage Pile (A-B) | TX | PSD | 04/13/06 | PM – 1.01 lbs/hr, 4.42 tpy (Pile 3) and 3.24 tpy (Pile A-B) $PM_{10}$ – 0.48 lbs/hr, 2.1 tpy (Pile 3) and 1.56 tpy (Pile A-B) | |
| NRG Texas –Inactive Pile | TX | PSD | 04/13/06 | PM – 18.4 tpy $PM_{10}$ – 9.02 tpy | |
| NRG Texas –Emergency Pile | TX | PSD | 04/13/06 | PM – 0.42 tpy $PM_{10}$ – 0.21 tpy | |
| Taylorville Energy Center | IL | | 06/15/07 | PM/$PM_{10}$ – 0.84 tons/year (handling and storage). | Absence of visible emissions or dust control program with at least 90% reduction. Could also include use of partial/total enclosure, adjustable feeders and drop systems, and compaction and/or chemical or wet suppression |
| Proposed Edwardsport IGCC Plant | IN | Application - Under Review | Aug 06 | ▪ Best management practices<br>▪ Fugitive dust control plan | |

**Table 12: Existing PM/$PM_{10}$/$PM_{2.5}$ BACT Limits - Slag Storage Piles**

| Facility | State | Application /Permit | Date | BACT Limit | BACT Control Method |
|---|---|---|---|---|---|
| Gary Coal Processing, LP – Slag Handling Activities | IN | | 07/19/06 | Opacity shall not exceed 10% on a 6 minute average | Fugitive dust control plan |
| **Taylorville Energy Center** | IL | | 06/15/07 | PM/$PM_{10}$ – 1.10 tons/year | Absence of visible emissions or dust control program with at least 90% reduction. Could also include use of partial/total enclosure, adjustable feeders and drop systems, and compaction and/or chemical or wet suppression |
| Proposed Edwardsport IGCC Plant | IN | Application - Under Review | Aug 06 | ▪ Best management practices<br>▪ Fugitive dust control plan<br>▪ Opacity shall not exceed 10% on a 6 minute average | |

(c) **New Source Performance Standards**
There are no established NSPS requirements that apply to PM emissions from the proposed coal handling operations.

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), the Permittee shall comply with the following requirements for particulate matter (PM / $PM_{10}$ / $PM_{2.5}$) for the proposed coal storage piles:

(1) Best management practices (including coal compaction); and

(2) Fugitive dust control plan including wet suppression as required by site conditions.

**Compliance Determination and Monitoring**

(1) Best management practices; and

(2) Fugitive dust control plan including wet suppression as required by site conditions.

**Particulate Matter (PM/ $PM_{10}$/ $PM_{2.5}$) BACT – Paved Roads**

*Step 2: Eliminate Technically Infeasible Options*

The RACT/BACT/LAER (RBLC) Clearinghouse and review of other New Source Review (NSR) permits reveal that the paved roads associated with recent power plant projects use of dust suppressants, roadway sweeping, covering of transport vehicles, and speed limits.

**Add-on Control Technology:**
Watering and the use of chemical wetting agents are the principal means for control of emissions from materials handling operations involving transfer of bulk minerals in aggregate form. Dust control can be achieved by: (a) source extent reduction (e.g., mass transfer reduction), (b) source improvement related to work practices and transfer equipment such as load-in and load-out operations (e.g., drop height reduction, wind sheltering, moisture retention)), and (c) surface treatment (e.g., wet suppression).

In most cases, good work practices which confine freshly exposed material provide substantial opportunities for emission reduction without the need for investment in a control application program. In particular, spillage of material caused by pile load-out and maintenance equipment can add a large source component associated with traffic entrained dust. The traffic dust component may easily dominate over emissions from transfer of material and wind erosion. The prevention of spillage and subsequent spreading of material by vehicles traversing the area is essential to cost-effective emission control. If spillage cannot be prevented because of the need for intense use of mobile equipment in the storage pile area, then regular cleanup should be employed as a necessary mitigative measure.

Fugitive emissions from paved roadways can also be controlled by wet suppression systems. These 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. The wetting agent can be water or a combination of water and a chemical surfactant. This surfactant, or surface active agent, reduces the surface tension of the water. As a result, the quantity of liquid needed to achieve good control is reduced.

The PM control options noted above are both feasible control alternatives. Therefore, there is no elimination of technically infeasible fugitive PM control alternatives. There are no other known control alternatives (per review of the BACT/LAER clearinghouse) that have been utilized on paved roads.

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness*

Development of a Fugitive Dust Control Plan which includes removal of deposits on roadways, speed limitation on vehicle traffic and wet suppression techniques as needed will be employed as BACT for paved roads.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 13 lists the proposed particulate BACT determination along with the existing particulate BACT determinations for the paved roads. All data in the table is based on the information obtained from the permit application submitted by Duke Energy Indiana, the U.S. EPA database of proposed gasification projects, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

(a) **Proposal**: Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN Development of a Fugitive Dust Control Plan which includes removal of deposits on roadways, speed limitation on vehicle traffic and wet suppression techniques as needed is proposed as BACT for particulate matter from paved roads:

(b) **Comparison with other BACT Limitations:**
Table 13 presents BACT limits for $PM/PM_{10}/PM_{2.5}$ emissions from paved roads. The limit being proposed by Duke is equivalent to the BACT limitations established for paved roads at these facilities

**Table 13: Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits - Fugitive Dust from Truck Traffic**

| Facility | State | Application / Permit | Date | BACT Limit | BACT Control Method |
|---|---|---|---|---|---|
| Homeland Energy Solutions, LLC | IA | Draft | 08/28/07 | PM – 96.48 tpy<br>$PM_{10}$ – 18.78 tpy | Best management practices with sweepers and dust suppressions |
| University of Northern Iowa<br>*Coal Pile Traffic | IA | | 5/3/2007 | $PM/PM_{10}$ – 80% reduction of silt load on paved roads (95% reduction of silt load on unpaved roads), | Use of dust suppressant (i.e., sweeping, water flushing, etc.) |
| Western Greenbrier Co-Generation, LLC | WV | | 04/26/06 | PM– 90% reduction | Maintain pavement, use of a vacuum sweeper and limit truck speed to 15 mph |
| Lamar Utilities Board DBA Lamar Light and Power | CO | | 02/03/06 | | $PM_{10}$ – Water wash down, daily inspection/cleanin g/covering of transport vehicles, watering |
| Public Service Company of Colorado | CO | | 07/05/05 | | $PM/PM_{10}$ – Swept and watered as necessary |

**Table 13: Existing PM/$PM_{10}$/$PM_{2.5}$ BACT Limits - Fugitive Dust from Truck Traffic**

| Facility | State | Application / Permit | Date | BACT Limit | BACT Control Method |
|---|---|---|---|---|---|
| Taylorville Energy Center | IL | | 06/15/07 | PM/$PM_{10}$ – Opacity does not exceed 15% | PM/$PM_{10}$ – Required work practices must include:<br>◊ Paving regularly traveled roads<br>◊ Treatment of roads for effective emission control, meet minimum nominal levels of emission control<br>◊ Handling of collected dust and preventing release back into environment |
| Proposed Edwardsport IGCC Plant | IN | Application - Under Review | Aug 06 | ▪ Incorporation of paved roads and a fugitive dust minimization program (including road sweeping and vehicle speed limitation<br>▪ Fugitive dust control plan | |

(c) **New Source Performance Standards**
There are no established NSPS requirements that apply to PM emissions from the proposed paved roads.

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), the Permittee shall develop a Fugitive Dust Control Plan which includes removal of deposits on roadways, speed limitation on vehicle traffic, wet suppression techniques as needed and opacity <15% for control of particulate matter (PM / $PM_{10}$ / $PM_{2.5}$) for the proposed paved roads:

**Compliance Determination and Monitoring**
Best management practices and a fugitive dust control plan including wet suppression, removal of deposits on roadways and minimizing vehicle speed.

**Requirement for CO BACT**

The following new emission units associated with the proposed IGCC plant at the Edwardsport Station have the potential to emit carbon monoxide (CO). Therefore, Best Available Control Technology analyses for CO were performed for these units:

(1) Two (2) combustion turbines, identified as CTHRSG1 and CTHRSG2, fired by syngas, natural gas or combined syngas/natural gas.

(2) One (1) 300 MMBtu/hr natural gas-fired auxiliary boiler, identified as AUXBLR.

(3) Two (2) natural gas-fired gasification pre-heater steam generation units, identified as GPREHEAT1 and GPREHEAT2 and two (2) natural gas-fired turbine gas conditioning heaters, identified as TPREHEAT1 and TPREHEAT2.

(4) One (1) 2200 brake horsepower (Bhp) diesel-fired emergency generator, identified as EMDSL.

(5) One (1) 420 brake horsepower (Bhp) diesel-fired emergency firewater pump, identified as FIRPMP.

(6) One (1) flare with a 1.23 MMBtu/hr natural gas fired pilot and 1.44 MMBtu/hr sweep gas / flare purge gas, identified as FLR.

(7) One (1) 3.85 MMBtu/hr natural gas-fired thermal oxidizer, identified as THRMOX.

## Carbon Monoxide (CO) BACT

*Step 1: Identify Potential Control Technologies*

Based on a review of the RBLC database and discussions with various individuals knowledgeable about similar operations, it was revealed that certain types of control technologies for CO abatement are generally available for fuel combustion devices. These control options have been reviewed for technical feasibility pertaining to the fuel combustion units proposed to be installed by Duke Energy Indiana. From the previously identified sources of information, the technologies available to potentially control CO emissions from fuel combustion units include the following:

(1) Combustion Control (including good combustion practices); and

(2) Oxidation Catalysts.

**<u>Combustion Control</u>**
Because CO is essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of CO emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

**<u>CO Oxidation Catalyst</u>**
Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO to $CO_2$ and water at temperatures approximately 50% lower than would be necessary for oxidation without a catalyst. The optimal working temperature range for CO oxidation catalysts is approximately 850°F - 1100°F with a minimum exhaust gas stream temperature of 500°F. At lower temperatures, the CO conversion efficiency drops off, while at temperatures greater than 1,200°F there is a potential for catalyst sintering. There are some careful catalyst configuration considerations in order to achieve effective operational efficiency. The CO catalyst needs to be strategically placed within the lateral dimensions of the combustion device exhaust to evenly distribute the gas flow across the catalyst.

*Step 2: Eliminate Technically Infeasible Options*

After detailed review, it was determined that the use of an oxidation catalyst was deemed technically infeasible and was excluded from further evaluation for the combustion turbine. A discussion on the potential technical constraints is provided below.

**Potential Technical Constraints**

Oxidation catalyst systems serve to remove CO from the combustion device exhaust gas by enhancing its oxidation to $CO_2$. The technology does not require introduction of additional chemicals for the reaction to proceed. The oxidation of CO to $CO_2$ utilizes the excess air present in the combustion device exhaust and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical considerations affecting the technology include:

(1) Catalyst reactor design;

(2) Optimum operating temperature;

(3) Back pressure loss to the system;

(4) Catalyst life; and

(5) The potential collateral increases in emissions of $PM/PM_{10}$.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons, causing a reduction in catalyst activity and pollutant removal efficiencies. Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO and VOC. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds such as the syngas stream. An oxidation catalyst system would be expected to convert up to 90 percent of the combustion turbine exhaust stream $SO_2$ to $SO_3$. If ammonia is also present as a result of an SCR control system, $SO_3$ and ammonia will react to form ammonium bisulfate. If ammonia is not present, $SO_3$ will combine with moisture in the gas stream to form $H_2SO_4$ mist. Due to the oxidation of $SO_2$ and excessive formation of either ammonium bisulfate or $H_2SO_4$ mist emissions, oxidation catalysts are not considered to be an appropriate control technology for combustion devices that are fired with fuels containing sulfur.

Use of oxidation catalyst controls for the syngas-fired combustion turbine is not transferable from a natural gas-fired combined-cycle unit for the following reasons:

(1) The combustion turbine will be a base-load generation facility and therefore must achieve the capacity factors, availability and reliability associated with base-load units. Any control system that causes forced outages, increases maintenance outage rates, or reduces unit efficiency appreciably is unacceptable since it would prevent the facility from serving its intended purpose as a base-load generation unit.

(2) Although oxidation catalyst technology is considered technically feasible for natural gas-fired combustion turbine/HRSG units, the Edwardsport combustion turbines must be available for firing with either syngas or natural gas. As a base-load unit, it would not be practical to install an oxidation catalyst system on a combustion turbine that would be capable of combusting duel fuels (i.e., syngas and natural gas)

**Environmental / Energy Impacts – Oxidation Catalyst**

A CO oxidation catalyst application has detrimental environmental consequences that need to be considered. Besides CO, the catalyst will also oxidize other species in the turbine exhaust. Any sulfur present in the natural gas (nominal fuel sulfur) will be oxidized to gas-phase $SO_2$ within the combustor and further oxidized to $SO_3$ across the catalyst.

In addition, disposal of the catalyst could represent a potential environmental impact. The catalysts used in combustion turbine applications must be replaced approximately every three years. The catalyst formulation contains heavy metals that may cause the spent catalyst to be considered as a hazardous waste requiring special handling during disposal. Note, however, that catalyst vendors may accept return of spent catalysts for recovery and reuse of the catalyst precious metals.

In addition to the operational and environmental impacts discussed above, there are also significant energy impacts associated with the application of CO oxidation catalysts. There is a loss of power output penalty, a loss of power demand penalty and a fuel penalty associated with the use of the catalyst. The increased backpressure in the turbine from the catalyst installation increases the heat input required and reduces the power output of the turbine and concurrently affects the power demand.

GE also stated in its white paper that other environmental impacts will result from the installation and operations of an oxidation catalyst on a combined cycle combustion system. With the installation of an oxidation catalyst, nitric oxide and sulfur dioxide present in the system exhaust will be oxidized by add-on catalysts to nitrogen dioxide and sulfur trioxide, both of which promote the formation of acid rain. In addition, if applied in combination with SCR, ammonium salts formed as a result of ammonia slip and sulfur trioxide will result in additional generation of $PM_{10}$ and accelerated corrosion of the heat recovery steam generator.

It can also be concluded that further reductions in CO emissions based on the inclusion of an oxidation catalyst will have minimal impacts on CO air quality. Due to the design of the exhaust gas combustion configuration on a combined cycle combustion system, the potential impact on CO air quality is typically insignificant. In fact, potential impacts on ambient air quality as predicted by USEPA dispersion models are shown to typically be less than 5% of the NAAQS based on previous analyses performed for similar sized combustion turbines. The NAAQS are standards developed by USEPA to project human health and welfare with a large margin of safety. These potential impacts are reflective of combined cycle combustion system operating with good combustion practices and exclusion of an oxidation catalyst.

According to a health risks study conducted by toxicologist R. A. Michaels (Ph.D, C.E.P., RAM TRAC Corporation) in a May 2001 report (*Carbon Monoxide Catalysis: Assessment of Need to Mitigate Public Health Risks Posed by Acute and Chronic Exposure to CO Emitted by Combined Cycle Natural Gas Turbines*), Dr. Michaels stated Risk posed to public health are quantified in this report to be zero, with or without CO catalysts. Indeed, this report reveals that ground level impacts of combined cycle natural gas turbines as modeled by GE are far from impacts which would be required to elicit adverse public health effects. Modeled turbine impacts would have to be increased by over an order of magnitude to elicit adverse effects associated herein with acute or chronic exposure to CO. (Information was extracted form GE's White Paper, Support for Elimination of Oxidation Catalyst Requirements for GEPG7241FA DLN Combustion Turbine, August 2001, mentioned above).

In looking at the potential environmental impacts, it has been concluded that installation of an oxidation catalyst would have more of an adverse environmental impact than those that would occur with the technology being proposed by Duke as BACT for CO emissions from combined cycle combustion units.

*Steps 3 through 5 of the CO BACT analyses are identified below for each emission unit listed previously under the category Requirement for CO BACT.*

**Carbon Monoxide (CO) BACT – Combined Cycle Combustion Turbine – Syngas Combustion**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of CO emissions from operation of the fuel combustion devices at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent tot the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 14 lists existing CO BACT determinations for combined-cycle combustion turbines designed to burn syngas.

(a) **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The following has been proposed as BACT for CO from each combined cycle combustion turbine associated with the IGCC plant while combusting syngas:

(1) Emission limitation of 0.046 lbs/MMBtu (HHV) – Based on the heat input to the combined cycle combustion turbine.

(2) Each combined cycle combustion turbine shall be maintained in good working order and shall be operated using good combustion practices using diffusion combustion technology.

(b) **Comparison with Other BACT Limitations**
The BACT limitation for CO emissions from the proposed combined cycle combustion turbines, CTHRSG1 and CTHRSG2, is equal to or more stringent than the BACT limitation for PM emissions from combustion turbines used in support of other IGCC facilities when combusting syngas with the exception of the following:

(1) **Tampa Electric PPS, Mulberry, Florida** - Although the Tampa Electric plant has a lower emission limit of 0.041 lbs/MMBtu, that limitation cannot be directly compared with the emission limit proposed by Duke Energy for the Edwardsport project. The emission limit for the Tampa plant is based on the combustion of petroleum coke and coal while the Edwardsport plant combusts only coal.

(2) **Cash Creek Generation, LLC** - Although the Cash Creek Generation plant has a lower emission limit of 0.36 lbs/MMBtu, that limitation cannot be directly compared with the emission limit proposed by Duke Energy for the Edwardsport project. The emission limit is part of a pending application that has not been granted a permit and thus will not be evaluated as BACT.

**Table 14: Existing CO BACT Limits – Combined Cycle Combustion Turbines (Syngas)**

| Facility | State | Application/ Permit | Date | Plant Output (MW) | Gasifier Fuel | Gasifier Make | Combustion Turbine | Syngas BACT Limit *(lb/MMBtu)** | Syngas BACT Limit *(lb/MMBtu)*** | BACT Control Method |
|---|---|---|---|---|---|---|---|---|---|---|
| Tampa Electric PPS | FL | Operating | 1996 | 250 | Petcoke / bit | GE (Texaco) | GE 7FA | 0.045 | 0.041 | GCP |
| Wabash River | IN | Operating | 1995 | 262 | Illinois bit | Conoco Phillips | F Class CTs | 0.036 | 0.056 | GCP |
| OUC/Southern Stanton Unit B | FL | Final Permit | Dec-06 | 285 | PRB | KBR | GE 7FA (1) | 0.0378 | - | GCP |
| Taylorville Energy Center (Erora Gp) | IL | Final Permit | Jun-07 | 677 | Illinois bit | GE (Texaco) | GE 7FA (2) | 0.035 | 0.049 | GCP |
| Lima Energy IGCC (Global Energy) | OH | Final Permit | Mar-02 | 530 | Petcoke / coal | Conoco Phillips | GE 7FA (2) | 0.035 | 0.137 | GCP |
| Southern Ill Clean Energy Ctr (Steelhead Energy) | IL | Application | Oct-04 | 544 | Illinois bit | Conoco Phillips | Not Available | 0.04 | - | GCP |
| Excelsior Energy - Mesaba | MN | Application | Jun-06 | 531 | Petcoke / coal | Conoco Phillips | SW SGT6-5000F | 0.033 | - | GCP |
| American Electric Power Great Bend (AEP) | OH | Application | Sep-06 | 629 | Eastern bit | GE (Texaco) | GE 7FB (2) | 0.031 | - | GCP |
| Appalachian Power Mountaineer (AEP) | WV | Application | Sep-06 | 600 | Eastern bit | GE (Texaco) | GE 7FB (2) | 0.031 | - | GCP |
| Energy Northwest | WA | Application | Sep-06 | 600 | Petcoke / coal | Conoco Phillips | SW SGT6-5000F | 0.036 | - | GCP |
| Nueces IGCC Plant (Tondu) | TX | Application | Sep-06 | 600 | Petcoke / coal | Shell | SW SGT6-5000F | 0.037 | - | GCP |
| Cash Creek Generation, LLC | - | Application | Mar-07 | 630 | Coal | - | - | - | 0.036 | GCP |
| Tampa Electric Polk Unit 6 Project | FL | Application (Withdrawn) | Sep-07 | 230 | Petcoke / coal | | GE 7FB | 0.032 | - | |

| | | |
|---|---|---|
| Maximum | 0.045 | 0.137 |
| Minimum | 0.031 | 0.036 |
| Average | 0.036 | 0.058 |

Notes:
* Based on heat input to the gasifier
** Based on heat input to combustion turbine
GCP = Good Combustion Practice

| Facility | State | Application/ Permit | Date | Plant Output (MW) | Gasifier Fuel | Gasifier Make | Combustion Turbine | Syngas BACT Limit *(lb/MMBtu)** | Syngas BACT Limit *(lb/MMBtu)*** | BACT Control Method |
|---|---|---|---|---|---|---|---|---|---|---|
| Proposed Edwardsport IGCC Plant | IN | Application - Under Review | Oct-07 | 630 | Coal | GE (Texaco) | GE 7FB | 0.037 | 0.046 | - |

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for CO for the combustion turbines associated with the proposed IGCC plant while combusting syngas:

(1) Emission limitation of 0.046 lbs/MMBtu (HHV) – Based on the heat input to the combined cycle combustion turbine; and

(2) Each combined cycle combustion turbine shall be maintained in good working order and shall be operated using good combustion practices using diffusion combustion technology.

**Compliance Determination and Monitoring**

(1) Recordkeeping of fuel usage and turbine heat inputs

(2) Emission estimates for CO, $PM/PM_{10}/PM_{2.5}$ and VOC based on recorded heat input information.

**Carbon Monoxide (CO) BACT – Combined Cycle Combustion Turbine – Natural Gas Combustion**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of CO emissions from operation of the fuel combustion devices at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent tot the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 15 lists existing CO BACT determinations for combined-cycle combustion turbines designed to burn natural gas.

(a) **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The following has been proposed as BACT for CO from the combined cycle combustion turbines associated with the IGCC plant: while combusting natural gas:

(1) Emission limitation of 0.042 lbs/MMBtu (HHV) – Based on the heat input to the combined cycle combustion turbine.

(2) Each combined cycle combustion turbine shall be maintained in good working order and shall be operated using good combustion practices using diffusion combustion technology.

(b) **Comparison with Other BACT Limitations**
The BACT limitation for CO emissions from the proposed combined cycle combustion turbines, CTHRSG1 and CTHRSG2, is equal to or more stringent than the BACT limitation for CO emissions from combustion turbines used in support of other IGCC facilities when combusting natural gas with the exception of the following:

(1) **OU Southern Stanton Unit B, Florida** - Although the OU Southern Stanton plant has a lower emission limit of 0.028 lbs/MMBtu, that limitation cannot be directly compared with the emission limit proposed by Duke Energy for the Edwardsport project. The emission limit for the OU Southern Stanton plant is based on gasifier fuel of petroleum coke and coal while the Edwardsport plant's gasifier fuel is only coal. In addition, the OU Southern Stanton plant is less than half of the size of the Duke plant.

(2) **Southern III Clean Energy Center** - Although the Southern III Clean Energy Center plant has a lower emission limit of 0.028 lbs/MMBtu, that limitation cannot be directly compared with the emission limit proposed by Duke Energy for the Edwardsport project. The emission limit is part of a pending application that has not been granted a permit and thus will not be evaluated as BACT. In addition, the turbine combustion type is not readily available.

(3) **Excelsior Energy – Mesaba, Minnesota** - Although the Excelsior Energy Center plant has a lower emission limit of 0.032 lbs/MMBtu, that limitation cannot be directly compared with the emission limit proposed by Duke Energy for the Edwardsport project. The emission limit is part of a pending application that has not been granted a permit and thus will not be evaluated as BACT. In addition, The emission limit for the Excelsior Energy plant is based on the combustion of petroleum coke and coal while the Edwardsport plant combusts only coal.

(4) **Energy Northwest, Washington** - Although the Energy Northwest plant has a lower emission limit of 0.035 lbs/MMBtu, that limitation cannot be directly compared with the emission limit proposed by Duke Energy for the Edwardsport project. The emission limit is part of a pending application that has not been granted a permit and thus will not be evaluated as BACT. In addition, The emission limit for the Excelsior Energy plant is based on the combustion of petroleum coke and coal while the Edwardsport plant combusts only coal.

**Table 15: Existing CO BACT Limits – Combined Cycle Combustion Turbines (Natural Gas)**

| Facility | State | Application / Permit | Date | Plant Output *(MW)* | Gasifier Fuel | Gasifier Make | Combustion Turbine | NG BACT Limit *(lb/MMBtu)* * | BACT Control Method |
|---|---|---|---|---|---|---|---|---|---|
| Wabash River | IN | Operating | 1995 | 262 | Illinois bit | Conoco Phillips | F Class CTs | Not Available | GCP |
| OUC/Southern Stanton Unit B | FL | Final Permit | Dec-06 | 285 | PRB | KBR | GE 7FA (1) | 0.028 | GCP |
| Taylorville Energy Center (Erora Gp) | IL | Final Permit | Jun-07 | 677 | Illinois bit | GE (Texaco) | GE 7FA (2) | 0.045 | GCP |
| Lima Energy IGCC (Global Energy) | OH | Final Permit | Mar-02 | 530 | Petcoke / coal | Conoco Phillips | GE 7FA (2) | 0.136 | GCP |
| Southern Ill Clean Energy Ctr (Steelhead Energy) | IL | Application | Oct-04 | 544 | Illinois bit | Conoco Phillips | Not Available | 0.028 | GCP |
| Excelsior Energy – Mesaba | MN | Application | Jun-06 | 531 | Petcoke / coal | Conoco Phillips | SW SGT6-5000F | 0.032 | GCP |
| American Electric Power Great Bend (AEP) | OH | Application | Sep-06 | 629 | Eastern bit | GE (Texaco) | GE 7FB (2) | Not Available | GCP |
| Appalachian Power Mountaineer (AEP) | WV | Application | Sep-06 | 600 | Eastern bit | GE (Texaco) | GE 7FB (2) | Not Available | GCP |
| Energy Northwest | WA | Application | Sep-06 | 600 | Petcoke / coal | Conoco Phillips | SW SGT6-5000F | 0.035 | GCP |
| Nueces IGCC Plant (Tondu) | TX | Application | Sep-06 | 600 | Petcoke / coal | Shell | SW 501 F (2) | 0.044 | GCP |
| Tampa Electric Polk Unit 6 Project | FL | Application (Withdrawn) | Sep-07 | 230 | Petcoke / coal | | GE 7FB | 0.047 | - |

Notes:
GCP = Good Combustion Practices
NA = Not applicable

| | |
|---|---|
| Maximum | 0.136 |
| Minimum | 0.028 |
| Average | 0.049 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Proposed Edwardsport IGCC Plant | IN | Application - Under Review | Oct-07 | 630 | Coal | GE (Texaco) | GE 7FB | 0.042 | - |

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for CO for the combustion turbines associated with the proposed IGCC plant while combusting natural gas:

(1) Emission limitation of 0.042 lbs/MMBtu (HHV) – Based on the heat input to the combined cycle combustion turbine.

(2) Each combined cycle combustion turbine shall be maintained in good working order and shall be operated using good combustion practices using diffusion combustion technology.

**Compliance Determination and Monitoring**

(1) Recordkeeping of fuel usage and turbine heat inputs

(2) Emission estimates for CO, PM/$PM_{10}$/$PM_{2.5}$ and VOC based on recorded heat input information.

**Carbon Monoxide (CO) Natural Gas-Fired Auxiliary Boiler**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of CO emissions from operation of the fuel combustion devices at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent to the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 16 lists the proposed CO BACT determination along with the existing CO determinations for the auxiliary boiler.

(a) **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN

(1) Maximum heat input of 300 MMBtu/hr and combustion of natural gas only;

(2) Emission Limitation of 0.036 lbs/MMBtu; and

(3) Boiler shall be maintained in good working order and shall be operated using good combustion practices.

(b) **Comparison with other BACT Limitations:**
Table 16 presents BACT limits for CO emissions from boilers. The limits being proposed by Duke is equivalent to or lower than the BACT limitations established for boilers at these facilities

**Table 16: Existing BACT Limits – Auxiliary Boiler**

| RBLC ID | Company | Permit Date | Heat Input *MMBtu/hr* | CO *lbs/MMBtu* |
|---|---|---|---|---|
| OH-0307 | Biomass Energy | 4/4/2006 | 247 | 0.11 |
| NV-0035 | Sierra Pacific Power Co. | 8/16/2005 | 159 | 0.036 |
| OH-0269 | Biomass Energy | 1/5/2004 | 247 | 0.11 |
| TX-0469 | Texas Petrochemicals LP | 10/8/2003 | 332 | 0.08 |
| IA-0067 | Mid-American Energy Co. | 6/17/2003 | 429 | 0.084 |
| NA | Taylorville Energy Center | 6/5/2007 | 279 | 0.037 |
| NA | Tampa Electric Polk Unit 6 Project | 9/7/2007 | 230 | 0.036 |
| | | Maximum | | 0.11 |
| | | Minimum | | 0.036 |
| | | Average | | 0.07 |
| Proposed Edwardsport IGCC Boiler | | - | 300 | 0.036 |

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for CO for the natural gas fired auxiliary boiler associated with the proposed IGCC plant:

(1) Maximum heat input of 300 MMBtu/hr and combustion of natural gas only;

(2) Emission Limitation of 0.036 lbs/MMBtu; and

(3) Boiler shall be maintained in good working order and shall be operated using good combustion practices.

**Compliance Determination and Monitoring**

Maintain records of the amount of natural gas combusted (MMCF) during each month.

**Carbon Monoxide (CO) Natural Gas-Fired Gasification Pre-Heaters and Turbine Gas Conditioning Heaters**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of CO emissions from operation of the fuel combustion devices at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent to the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 17 lists the proposed CO BACT determination along with the existing CO determinations for the natural gas fired gasification pre-heaters and turbine gas conditioning heaters.

**(a)** **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN

(1) Emission limitation of 0.08 lbs/MMBtu for CO emissions from gasification heaters.

(2) Emission limitation of 0.10 lbs/MMBtu for CO emissions from turbine gas conditioning heaters.

(3) Use of only natural gas.

(4) Maximum heat input of gasifier heaters and turbine gas conditioning heaters 38.2 and 10.0 MMBtu/hr, respectively.

(5) Gasification preheaters and turbine gas conditioning heaters will be maintained in good working order and operated with good combustion practices.

**(b) Comparison with Other BACT Limitations**

Natural Gas Fired Gasification Pre-Heaters
The BACT limitation for CO emissions from the proposed natural gas fired gasification pre-heaters is equal to or more stringent than the BACT limitation for other similar auxiliary boilers with the exception of the following:

**WE Energies (WEPCO) - Port Washington Generating Station (WI).** Although WE Energies has a BACT limit of 0.047 lbs CO/MMBtu, this limit is a calculated value. Duke's proposed BACT limit of 0.08 lbs CO/MMBtu is based on the AP-42 emission factor for small natural gas fired heaters.

Natural Gas Fired Turbine Gas Conditioning Heaters
The proposed BACT limitation for CO emissions from the proposed natural gas fired turbine gas conditioning heaters is higher than the BACT limitations for other natural gas fired boilers/heaters. This turbine gas conditioner heater is a process specific piece of equipment that is designed to meet the unique needs of the IGCC facility. The proposed BACT limitation of 0.1 lbs CO/MMBtu is based on the manufacturer's specifications. As discussed previously, add-on controls are not technically feasible for this type of small heater.

**Table 17: BACT Limits – CO for Natural Gas Fired Boilers/Heaters (<100 MMBtu/hr)**

| Facility Name | Permit ID | Permit Date | Equipment Type and Heat Input | CO Limits |
|---|---|---|---|---|
| Daimler Chrysler Corporation - Toledo Supplier Park Paint Shop (OH) | 04-01358 | 5/3/2007 | Natural Gas Boiler - 20.40 MMBtu/hr | 1.7 lb/hr<br>7.5 tons/year<br>0.083 lbs/MMBtu |
| WE Energies (WEPCO) - Port Washington Generating Station (WI) | 04-RV-175 | 10/13/2004 | Natural Gas Heater - 10.0 MMBtu/hr | 0.47 lbs/hr<br>0.047 lbs/MMBtu<br>(Calculated) |
| Steelcorr Inc - Bluewater Project (AR) | 2062-AOP-R0 | 7/22/2004 | Natural Gas Boiler - 22 MMBtu/hr | 0.84 lbs/MMBtu |
| Ace Ethanol, LLC - Ace Ethanol - Stanley (WI) | 03-DCF-184 | 1/21/2004 | Natural Gas Boiler - 11.0 MMBtu/hr | 0.08 lb/MMBtu |
| Interstate Power & Light - Emery Generating Station (IA) | 17-02-016 | 6/26/2003 | Natural Gas Heater - 9.0 MMBtu/hr | 3.25 tons/year<br>0.082 lbs/MMBtu |

**Table 17: BACT Limits – CO for Natural Gas Fired Boilers/Heaters (<100 MMBtu/hr)**

| Facility Name | Permit ID | Permit Date | Equipment Type and Heat Input | CO Limits |
|---|---|---|---|---|
| Charter Manufacturing Co - Charter Steel | 13-04176 | 4/14/2003 | Natural Gas Boiler - 25 lbs/MMBtu | 2.06 lbs/hr<br>9.02 tons/year |
| COS-MAR Company - Styrene Monomer Plant (LA) | PSD-LA-690 | 2/11/2003 | Gas Heater - 14.4 lbs/MMBtu | 1.2 lbs/hr<br>0.08 lbs/MMBtu |
| Degussa Engineered Carbons, LP - Baytown Carbon Black Plant (TX) | PSD-1010 | 12/31/2002 | Back-Up Boiler - 13.4 lbs/MMBtu | 1.11 lbs/hr<br>4.85 tons/year |

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for CO for the natural gas fired gasification pre-heaters and turbine gas conditioning heaters associated with the proposed IGCC plant:

(1) Emission limitation of 0.08 lbs/MMBtu for CO emissions from gasification heaters.

(2) Emission limitation of 0.10 lbs/MMBtu for CO emissions from turbine gas conditioning heaters.

(3) Use of only natural gas.

(4) Maximum heat input of gasifier heaters and turbine gas conditioning heaters 38.2 and 10.0 MMBtu/hr, respectively.

(5) Gasification preheaters and turbine gas conditioning heaters will be maintained in good working order and operated with good combustion practices.

**Compliance Determination and Monitoring**

(1) Confirmation that pipeline natural gas is being combusted.

(2) Recordkeeping of natural gas usage.

(3) Emission estimates based on recorded natural gas usage and AP-42 emission factors.

**Carbon Monoxide (CO) BACT - Emergency Generator and Emergency Fire Pump**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of CO emissions from operation of the fuel combustion devices at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent to the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

**(a)** **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN

(1) Compliance with NSPS IIII; and

(2) Good combustion/operating practices.

(b) **New Source Performance Standards**
NSPS Subpart IIII applies to the emergency generator and fire pump. The proposed BACT for control of CO from emergency generator and fire pump is equivalent to the emission limitation required by NSPS Subpart IIII.

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for CO for the natural gas fired gasification pre-heaters and turbine gas conditioning heaters associated with the proposed IGCC plant:

(1) Compliance with NSPS IIII; and

(2) Good combustion/operating practices.

**Compliance Determination and Monitoring**

(1) Certification/plant documentation on meeting NSPS Subpart IIII emission limitations

(2) Recordkeeping of fuel usage.

**Carbon Monoxide (CO) Flare Pilot and Gasification Startup**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of CO emissions from operation of the fuel combustion devices at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent to the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

(a) **Proposal**: Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN

(1) The gasification flare shall be maintained in good working order and shall operate per manufacturer's specifications.

(2) The CO emissions from the gasification flare pilot shall not exceed 0.08 lbs/MMBtu.

(3) Combustion of only natural gas in gasification flare pilot burner.

(4) CO emissions from the gasification flare shall not exceed 34.6 tons/year during startup operations.

(b) **Comparison with Other BACT Limitations**

Review of Information on the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies reveals that limited information is available on CO emissions from a flare that supports a gasification process. Review of the Taylorville IGCC permit indicates that BACT for the gasification flare is the combustion of only natural gas in the flare pilot, operation of the flare pilot at all times, and good combustion practices.

(c) **New Source Performance Standards**
There are no NSPS requirements for the flare pilot and gasification startup equipment.

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for CO for the flare pilot and gasification startup equipment associated with the proposed IGCC plant:

(1) The gasification flare shall be maintained in good working order and shall operate per manufacturer's specifications.

(2) The CO emissions from the gasification flare pilot shall not exceed 0.08 lbs/MMBtu.

(3) Combustion of only natural gas in gasification flare pilot burner.

(4) CO emissions from the gasification flare shall not exceed 34.6 tons/year during startup operations.

**Compliance Determination and Monitoring**

(1) Operate with a flame present at all times when emissions are vented to the flare;

(2) Test volume flow rate to flare during startup event and confirm/certify heating value of volume flow rate.

(3) Within 10 days of initial startup of any unit in the gasification block, confirm flare is in compliance with 40 CFR 60.18. Permittee must maintain appropriate documentation to demonstrate that identified process operation gas streams are connected to the flare header.

(4) Record of amount of natural gas combusted (MMCF) during each month, continuous presence of flare pilot flame and no visual emissions.

(5) Continuous monitoring of gas flow rate to flame.

(6) Determine visual emissions by Reference Method 22.

(7) Record hours of startup events. Emission estimates based hours of startup and pound per event emission factors.

**Carbon Monoxide (CO) Thermal Oxidizer Burner and Gasification Operation**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of CO emissions from operation of the fuel combustion devices at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent to the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

(a) **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN

(1) The thermal oxidizer shall be maintained in good working order and shall operate per manufacturer's specifications.

(2) The CO emissions from the gasification thermal oxidizer burner shall not exceed 0.08 lbs/MMBtu.

(3) Combustion of only natural gas in gasification thermal oxidizer burner.

(4) CO emissions from the gasification thermal oxidizer shall not exceed 6.2 tpy during startup operations.

(b) **Comparison with Other BACT Limitations**
The BACT limitation for CO emissions from the proposed gasification thermal oxidizer is equal to or more stringent than the BACT limitation for other gasification oxidizers.

(c) **New Source Performance Standards**
There are no NSPS requirements for the thermal oxidizer burner and gasification operations.

*Step 5: Select BACT*

Pursuant to 326 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for CO for the thermal oxidizer burner associated with the proposed IGCC plant:

(1) The thermal oxidizer shall be maintained in good working order and shall operate per manufacturer's specifications.

(2) The CO emissions from the gasification thermal oxidizer shall not exceed 0.08 lbs/MMBtu.

(3) Combustion of only natural gas in gasification thermal oxidizer burner.

(4) CO emissions from the gasification thermal oxidizer shall not exceed 6.2 tpy during startup operations.

**Compliance Determination and Monitoring**

(1) Operate at all times when an emission point vented to thermal oxidizer is in operation.

(2) Amount of natural gas combusted (MMCF) during each month, date/time thermal oxidizer is not in operation.

(3) Maintain daily records of visible emission notations of stack exhaust shall be performed once per day during normal daylight operations.

(4) Maintain continuous temperature records (3-hr average).

(5) Temperature shall be at or above the 3-hr average of 1,400 °F.

(5) Continuous Monitoring System for measuring operating temperature. Recorded as a 3-hr average.

**Requirement for VOC BACT**

The following new emission units associated with the proposed IGCC plant at the Edwardsport Station have the potential to emit Volatile Organic Compounds (VOC) therefore, a Best Available Control Technology analyses for VOC were performed for these units:

(1) Two (2) syngas/natural gas and combined syngas/natural gas-fired combustion turbines, identified as CTHRSG 1 and CTHRSG 2.

(2) One (1) 300 MMBtu/hr natural gas-fired auxiliary boiler, identified as AUXBLR.

(3) Two (2) natural gas-fired gasification pre-heater steam generation units, identified as GPREHEAT1 and GPREHEAT2 and two (2) natural gas-fired turbine gas conditioning heaters, identified as TPREHEAT1 and TPREHEAT2.

(4) One (1) 2200 brake horsepower (Bhp) diesel-fired emergency generator, identified as EMDSL.

(5) One (1) 420 brake horsepower (Bhp) diesel-fired emergency firewater pump, identified as FIRPMP.

(6) One (1) flare with a 1.23 MMBtu/hr natural gas fired pilot and 1.44 MMBtu/hr sweep gas and flare purge gas, identified as FLR.

(7) One (1) 3.85 MMBtu/hr natural gas-fired thermal oxidizer, identified as THRMOX.

326 IAC 8-1-6 requires new facilities which have potential emissions of 25 tons or more per year, located anywhere in the state, which are not otherwise regulated by 326 IAC 8, to reduce VOC emissions using Best Available Control Technology (State BACT). The requirements of 326 IAC 2-2-3 satisfy the requirements of 326 IAC 8-1-6.

**Volatile Organic Compounds (VOC) BACT**

*Step 1: Identify Potential Control Technologies*

Based on a review of the RBLC database and discussions with various individuals knowledgeable about similar operations, it was revealed that certain types of control technologies for VOC abatement are available for fuel combustion devices. These control options have been reviewed for technical feasibility pertaining to the fuel combustion units proposed to be installed by Duke Energy Indiana. From the previously identified sources of information, the technologies available to potentially control VOC emissions from fuel combustion units include the following:

(1) Combustion Control (including good combustion practices); and

(2) VOC Oxidation Catalyst.

**Combustion Control**
Because VOC is essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of VOC emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

**VOC Oxidation Catalyst**
Noble Metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation at temperatures approximately 50% lower than would be necessary for oxidation without a catalyst. The optimal working temperature range for an oxidation catalyst is approximately 850°F - 1100°F with a minimum exhaust gas stream temperature of 500°F. At lower temperatures, the oxidation conversion efficiency drops off, while at temperatures greater than 1,200°F there is a potential for catalyst sintering. There are some careful placement considerations in order to achieve effective operational efficiency. The VOC catalyst needs to be strategically placed within the proper combustion device exhaust lateral distribution to evenly distribute the gas flow across the catalyst.

*Step 2: Eliminate Technically Infeasible Options*

After detailed review, it was determined that the use of an oxidation catalyst was deemed technically infeasible and was excluded from further evaluation for the combustion turbine. A discussion on the potential technical constraints is provided below.

**Potential Technical Constraints**
Oxidation catalyst systems serve to remove combustion byproducts from the combustion device exhaust gas by enhancing its oxidation to $CO_2$. The technology does not require introduction of additional chemicals for the reaction to proceed. The oxidation of $CO_2$ utilizes the excess air present in the combustion device exhaust and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical considerations affecting the technology include:

(1) Catalyst reactor design;

(2) Optimum operating temperature;

(3) Back pressure loss to the system;

(4) Catalyst life; and

(5) The potential collateral increases in emissions of $PM/PM_{10}$.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons, causing a reduction in catalyst activity and pollutant removal efficiencies. Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO and VOC. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds such as the syngas stream. An oxidation catalyst system would be expected to convert up to 90 percent of the combustion turbine exhaust stream $SO_2$ to $SO_3$. If ammonia is also present as a result of an SCR control system, $SO_3$ and ammonia will react to form ammonium bisulfate. If ammonia is not present, $SO_3$ will combine with moisture in the gas stream to form $H_2SO_4$ mist. Due to the oxidation of $SO_2$ and excessive formation of either ammonium bisulfate or $H_2SO_4$ mist emissions, oxidation catalysts are not considered to be an appropriate control technology for combustion devices that are fired with fuels containing sulfur.

Use of oxidation catalyst controls for the combustion turbine is not transferable from a natural gas-fired combined-cycle unit for the following reasons:

(1) The combustion turbine will be a base-load generation facility and therefore must achieve the capacity factors, availability and reliability associated with base-load units. Any control system that causes forced outages, increases maintenance outage rates, or reduces unit efficiency appreciably is unacceptable since it would prevent the facility from serving its intended purpose as a base-load generation unit.

(2) Use of oxidation catalyst will significantly exacerbate the formation of ammonium bisulfate by substantially increasing $SO_3$, as up to 90 percent of $SO_2$ will be oxidized to $SO_3$ by an oxidation catalyst. During syngas firing, this will significantly increase the formation of ammonium bisulfate.

(3) Although oxidation catalyst technology is considered technically feasible for natural gas-fired combustion turbine/HRSG units, the Edwardsport combustion turbines, must be available for firing with either syngas or natural gas. As a base-load unit, it would not be practical to install an oxidation catalyst system on a combustion turbine that would be capable of combusting duel fuels (i.e., syngas and natural gas).

(4) GE stated in its White Paper that oxidation catalysts can be used to reduce VOC emissions from combustion turbines. However, GE Frame 7 combustion turbines typically produce very low, or even negligible, VOC emissions. Thus, incorporation of an oxidation catalyst would have an insignificant reduction in VOC emissions.

**<u>Environmental / Energy Impacts – Oxidation Catalyst</u>**

An oxidation catalyst application has detrimental environmental consequences that need to be considered. Besides VOC, the catalyst will also oxidize other species in the turbine exhaust. Any sulfur present in the natural gas (nominal fuel sulfur) will be oxidized to gas-phase $SO_2$ within the combustor and further oxidized to $SO_3$ across the catalyst.

In addition, disposal of the catalyst could represent a potential environmental impact. The catalysts used in combustion turbine applications must be replaced approximately every three years. The catalyst formulation contains heavy metals that may cause the spent catalyst to be considered as a hazardous waste requiring special handling during disposal. Note, however, that catalyst vendors may accept return of spent catalysts for recovery and reuse of the catalyst precious metals.

In addition to the operational and environmental impacts discussed above, there are also significant energy impacts associated with the application of VOC oxidation catalysts. There is a loss of power output penalty, a loss of power demand penalty and a fuel penalty associated with the use of the catalyst. The increased backpressure in the turbine from the catalyst installation increases the heat input required and reduces the power output of the turbine and concurrently affects the power demand.

GE also stated in its white paper that other environmental impacts will result from the installation and operations of an oxidation catalyst on a combined cycle combustion system. With the installation of an oxidation catalyst, nitric oxide and sulfur dioxide present in the system exhaust will be oxidized by add-on catalysts to nitrogen dioxide and sulfur trioxide, both of which promote the formation of acid rain. In addition, if applied in combination with SCR, ammonium salts formed as a result of ammonia slip and sulfur trioxide will result in additional generation of $PM_{10}$ and accelerated corrosion of the heat recovery steam generator.

In looking at the potential environmental impacts, it has been concluded that installation of an oxidation catalyst would have more of an adverse environmental impact than those that would occur with the technology being proposed by Duke as BACT for VOC emissions from combined cycle combustion units.

*Steps 3 through 5 of the VOC BACT analyses are identified below for each emission unit listed previously under the category Requirement for VOC BACT.*

**Volatile Organic Compounds (VOC) BACT – Combined Cycle Combustion Turbine – Natural Gas Combustion**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of VOC emissions from operation of the fuel combustion devices at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent tot the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 18 lists the proposed VOC BACT determination along with the existing VOC determinations for combined-cycle combustion turbines designed to burn syngas.

(a) **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN The following has been proposed as BACT for VOC emissions from the combustion turbines associated with the IGCC plant while combusting syngas:

(1) Emission limitation of 0.002 lbs/MMBtu (HHV) – Based on the heat input into the combined cycle combustion turbine.

(2) Each combined cycle combustion turbine shall be maintained in good working order and shall be operated using good combustion practices using diffusion combustion technology.

(b) **Comparison with other BACT limitations**
The VOC BACT limitations being proposed for the IGCC combustion turbines while combusting syngas is equivalent to limitations established for similar combustion devices at other IGCC facilities.

**Table 18: Existing VOC BACT Limits – Combined Cycle Combustion Turbines (Syngas)**

| Facility | State | Application/ Permit | Date | Plant Output *(MW)* | Gasifier Fuel | Gasifier Make | Combustion Turbine | Syngas `BACT Limit *(lb/MMBtu)** | BACT Control Method |
|---|---|---|---|---|---|---|---|---|---|
| Tampa Electric PPS | FL | Operating | 1996 | 250 | Petcoke / bit | GE (Texaco) | GE 7FA | 0.0017 | - |
| Wabash River | IN | Operating | 1995 | 262 | Illinois bit | Conoco Phillips | F Class CTs | 0.0021 | - |
| Taylorville Energy Center (Erora Gp) | IL | Final Permit | Jun-07 | 677 | Illinois bit | GE (Texaco) | GE 7FA (2) | 0.006 | - |
| Lima Energy IGCC (Global Energy) | OH | Final Permit | Mar-02 | 530 | Petcoke / coal | Conoco Phillips | GE 7FA (2) | 0.0082 | - |
| Cash Creek Generation, LLC | - | Application | | 667 | Coal | - | - | 0.006 | - |
| Tampa Electric Polk Unit 6 Project | FL | Application (Withdrawn) | Sep-07 | 230 | Petcoke / coal | | GE 7FB | 0.0012 | |

Notes:

* Based on heat input to combustion turbine

| | |
|---|---|
| Maximum | 0.0082 |
| Minimum | 0.0012 |
| Average | 0.004 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Proposed Edwardsport IGCC Plant | IN | Application - Under Review | Oct-07 | 630 | Coal | GE (Texaco) | GE 7FB | 0.002 | - |

(c) **New Source Performance Standards**
There are no NSPS requirements for VOC emissions from combustion turbines.

*Step 5: Select BACT*

Pursuant to 320 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for VOC for the combustion turbines associated with the proposed IGCC plant while combusting syngas:

(1) Emission limitation of 0.002 lbs/MMBtu (HHV) – Based on the heat input to the combined cycle combustion turbine.
(2) Each combined cycle combustion turbine shall be maintained in good working order and shall be operated using good combustion practices using diffusion combustion technology.

**Compliance Determination and Monitoring**

(1) Compliance with PM limits for syngas combustion will be based on initial compliance testing through stack testing based on NSPS requirements.

(2) Recordkeeping of fuel usage and turbine heat inputs.

(3) Emission estimates for VOC based on recorded heat input information and tested emission factor (lbs/MMBtu).

**Volatile Organic Compounds (VOC) BACT – Combined Cycle Combustion Turbine – Natural Gas Combustion**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of VOC emissions from operation of the fuel combustion devices at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent tot the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 19 lists the proposed VOC BACT determination along with the existing VOC determinations for combined-cycle combustion turbines designed to burn natural gas.

(a) **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The following has been proposed as BACT for VOC from the combustion turbines associated with the IGCC plant while combusting natural gas:

(1) Emission limitation of 0.002 lbs/MMBtu (HHV) – Based on the heat input into the combined cycle combustion turbine.

(2) Each combined cycle combustion turbine shall be maintained in good working order and shall be operated using good combustion practices using diffusion combustion technology.

(b) **Comparison with other BACT limitations**
The VOC BACT limitations being proposed for the IGCC combustion devices is equivalent to limitations established for similar combustion devices at other IGCC facilities.

**Table 19: Existing VOC BACT Limits – Combined Cycle Combustion Turbines (Natural Gas)**

| Facility | State | Application/ Permit | Date | Plant Output *(MW)* | Gasifier Fuel | Gasifier Make | Combustion Turbine | NG BACT Limit *(lb/MMBtu)** | BACT Control Method |
|---|---|---|---|---|---|---|---|---|---|
| Wabash River | IN | Operating | 1995 | 262 | Illinois bit | Conoco Phillips | F Class CTs | Not Available | GCP |
| OUC/Southern Stanton Unit B | FL | Final Permit | Dec-06 | 285 | PRB | KBR | GE 7FA (1) | 0.028 | GCP |
| Taylorville Energy Center (Erora Gp) | IL | Final Permit | Jun-07 | 677 | Illinois bit | GE (Texaco) | GE 7FA (2) | 0.045 | GCP |
| Lima Energy IGCC (Global Energy) | OH | Final Permit | Mar-02 | 530 | Petcoke / coal | Conoco Phillips | GE 7FA (2) | 0.136 | GCP |
| Southern Ill Clean Energy Ctr (Steelhead Energy) | IL | Application | Oct-04 | 544 | Illinois bit | Conoco Phillips | Not Available | 0.028 | GCP |
| Excelsior Energy – Mesaba | MN | Application | Jun-06 | 531 | Petcoke / coal | Conoco Phillips | SW SGT6-5000F | 0.032 | GCP |
| American Electric Power Great Bend (AEP) | OH | Application | Sep-06 | 629 | Eastern bit | GE (Texaco) | GE 7FB (2) | Not Available | GCP |
| Appalachian Power Mountaineer (AEP) | WV | Application | Sep-06 | 600 | Eastern bit | GE (Texaco) | GE 7FB (2) | Not Available | GCP |
| Energy Northwest | WA | Application | Sep-06 | 600 | Petcoke / coal | Conoco Phillips | SW SGT6-5000F | 0.035 | GCP |
| Nueces IGCC Plant (Tondu) | TX | Application | Sep-06 | 600 | Petcoke / coal | Shell | SW 501 F (2) | 0.044 | GCP |
| Calpine Corp | CA | - | May-06 | 300 | - | - | - | 0.0029 | GCP/Oxidation Catalyst |
| Tampa Electric Polk Unit 6 Project | FL | Application (Withdrawn) | Sep-07 | 230 | Petcoke / coal | | GE 7FB | 0.0017 | - |
| | | | | | | | Maximum | 0.136 | |
| | | | | | | | Minimum | 0.0017 | |
| | | | | | | | Average | 0.039 | |
| Proposed Edwardsport IGCC Plant | IN | Application - Under Review | Oct-07 | 630 | Coal | GE (Texaco) | GE 7FB | 0.002 | - |

Notes:
F = limit based on filterable (front half) PM testing
F/B = limit based on filterable (front half) and condensable (back half) PM testing
NA = Not applicable
GCP = Good Combustion Practice
* Based on heat input to combustion turbine
** This PM limit is being proposed as LAER

(c) **New Source Performance Standards**
There are no NSPS requirements for VOC emissions from combustion turbines.

*Step 5: Select BACT*

Pursuant to 320 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for VOC for the combustion turbines associated with the proposed IGCC plant when combusting natural gas:

(1) Emission limitation of 0.002 lbs/MMBtu (HHV) – Based on the heat input to the combined cycle combustion turbine.

(2) Each combined cycle combustion turbine shall be maintained in good working order and shall be operated using good combustion practices using diffusion combustion technology.

**Compliance Determination and Monitoring**

(1) Initial compliance test following 40 CFR 60.8. For VOC one (1) turbine will be tested since both units are identical. Testing to include natural gas and syngas.

(2) Recordkeeping of fuel usage and turbine heat inputs.

(3) Emission estimates for VOC based on recorded heat input information

**Volatile Organic Compounds (VOC) BACT – Auxiliary Boiler**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of VOC emissions from operation of the auxiliary boiler at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent tot the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 20 lists the proposed VOC BACT determination along with the existing VOC determinations for the natural gas-fired auxiliary boiler.

(a) **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The following has been proposed as BACT for VOC from each individual fuel combustion device associated with the IGCC plant:

(1) Maximum heat input of 300 MMBtu/hr and combustion of natural gas only.

(2) Emission Limitation of 0.005 lbs/MMBtu

(3) Boiler shall be maintained in good working order and shall be operated using good combustion practices.

(b) **Comparison with other BACT limitations**
The VOC BACT limitations being proposed for the auxiliary boiler is equivalent to limitations established for similar combustion devices at other facilities.

**Table 20: Existing BACT Limits – Auxiliary Boiler**

| RBLC ID | Company | Permit Date | Heat Input *MMBtu/hr* | VOC *lbs/MMBtu* |
|---|---|---|---|---|
| OH-0307 | Biomass Energy | 4/4/2006 | 247 | 0.004 |
| NV-0035 | Sierra Pacific Power Co. | 8/16/2005 | 159 | 0.005 |
| OH-0269 | Biomass Energy | 1/5/2004 | 247 | 0.004 |
| IA-0067 | Mid-American Energy Co. | 6/17/2003 | 429 | 0.055 |
| NA | Longview Power, LLC | 3/2/2004 | NA | 0.0054 |
| NA | Columbia Energy Center | 7/3/2003 | NA | 0.004 |
| NA | Weyerhaeuser Company | 11/15/2002 | NA | 0.01 |
| NA | Tampa Electric Polk Unit 6 Project | 9/7/2007 | 230 | 0.011 |
| | | Maximum | 429 | 0.055 |
| | | Minimum | 60 | 0.004 |
| | | Average | 248 | 0.01 |
| Proposed Edwardsport IGCC Boiler | | - | 300 | 0.005 |

(c) **New Source Performance Standards**
There are no NSPS requirements for VOC emissions from the auxiliary boiler.

*Step 5: Select BACT*

Pursuant to 320 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for VOC for the fuel combustion devices associated with the proposed IGCC plant:

(1) Maximum heat input of 300 MMBtu/hr and combustion of natural gas only.

(2) Emission Limitation of 0.005 lbs/MMBtu

(3) Boiler shall be maintained in good working order and shall be operated using good combustion practices.

**Compliance Determination and Monitoring**

Maintain records of the amount of natural gas combusted (MMCF) during each month.

**Volatile Organic Compounds (VOC) BACT – Natural Gas Fired Pre-Heaters and Turbine Gas Conditioning Heaters**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of VOC emissions from operation of the natural gas fired pre-heaters and turbine gas conditioning heaters at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent tot the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 21 lists the proposed VOC BACT determination along with the existing VOC determinations for small natural gas fired boilers/heaters.

(a) **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN

(1) Emission limitation of 0.005 lbs/MMBtu for VOC emissions from gasification heaters.

(2) Emission limitation of 0.038 lbs/MMBtu for VOC emissions from turbine gas conditioning heaters.

(3) Use of only natural gas.

(4) Maximum heat input of gasifier heaters and turbine gas conditioning heaters 38.2 and 10.0 MMBtu/hr, respectively.

(5) Gasification preheaters and turbine gas conditioning heaters will be maintained in good working order and operated with good combustion practices.

(b) **Comparison with other BACT limitations**
The VOC BACT limitations being proposed for the natural gas fired pre-heaters and turbine gas conditioning heaters is equivalent to limitations established for similar combustion devices at other facilities.

**Table 21: BACT Limits – VOC for Natural Gas Fired Boilers/Heaters <100 MMBtu/hr)**

| Facility Name | Permit ID | Permit Date | Equipment Type and Heat Input | VOC Limits |
|---|---|---|---|---|
| Daimler Chrysler Corporation - Toledo Supplier Park Paint Shop (OH) | 04-01358 | 5/3/2007 | Natural Gas Boiler - 20.40 MMBtu/hr | 0.11 lb/hr<br>0.5 tons/year<br>0.0054 lbs/MMBtu |
| WE Energies (WEPCO) - Port Washington Generating Station (WI) | 04-RV-175 | 10/13/2004 | Natural Gas Heater - 10.0 MMBtu/hr | 0.06 lbs/hr<br>0.006 lbs/MMBtu |
| Steelcorr Inc -Bluewater Project (AR) | 2062-AOP-R0 | 7/22/2004 | Natural Gas Boiler -<br>22 MMBtu/hr | 0.0055 lbs/MMBtu |
| Nucor Steel Corp - Nucor Steel Division (NE) | 35677RC3 | 6/22/2004 | Post Heater - 6.8 MMBtu/hr | 0.0055 lbs/MMBtu |
| Ace Ethanol, LLC -Ace Ethanol - Stanley (WI) | 03-DCF-184 | 1/21/2004 | Natural Gas Boiler - 11.0 MMBtu/hr | 0.0054 lbs/MMBtu |
| Interstate Power & Light -Emery Generating Station (IA) | 17-02-016 | 6/26/2003 | Natural Gas Heater - 9.0 MMBtu/hr | 0.21 tons/year<br>0.0054 lbs/MMBtu |
| Oglethorpe Power Corporation - Talbot Energy Facility (GA) | 4911-263-0013-P-03-0 | 6/9/2003 | Fuel Gas Preheaters -5.0 MMBtu/hr | -- |

**Table 21: BACT Limits – VOC for Natural Gas Fired Boilers/Heaters <100 MMBtu/hr)**

| Facility Name | Permit ID | Permit Date | Equipment Type and Heat Input | VOC Limits |
|---|---|---|---|---|
| Charter Manufacturing Co -Charter Steel | 13-04176 | 4/14/2003 | Natural Gas Boiler - 25 lbs/MMBtu | 0.13 lbs/hr 0.59 tons/year |
| COS-MAR Company -Styrene Monomer Plant (LA) | PSD-LA-690 | 2/11/2003 | Gas Heater - 14.4 lbs/MMBtu | -- |
| Degussa Engineered Carbons, LP -Baytown Carbon Black Plant (TX) | PSD-1010 | 12/31/2002 | Back-Up Boiler -13.4 lbs/MMBtu | 0.08 lbs/hr 0.35 tons/yr |

(c) **New Source Performance Standards**
There are no NSPS requirements for VOC emissions from the auxiliary boiler.

*Step 5: Select BACT*

Pursuant to 320 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for VOC for the natural gas fired pre-heaters and turbine gas conditioning heaters associated with the proposed IGCC plant:

(1) Emission limitation of 0.005 lbs/MMBtu for VOC emissions from gasification heaters.

(2) Emission limitation of 0.038 lbs/MMBtu for VOC emissions from turbine gas conditioning heaters.

(3) Use of only natural gas.

(4) Maximum heat input of gasifier heaters and turbine gas conditioning heaters 38.2 and 10.0 MMBtu/hr, respectively.

(5) Gasification preheaters and turbine gas conditioning heaters will be maintained in good working order and operated with good combustion practices.

**Compliance Determination and Monitoring**

(1) Confirmation that pipeline quality natural gas is being combusted

(2) Vendor guarantee on emission limits

(3) Recordkeeping of natural gas usage

(4) Emission estimates based on recorded natural gas usage and AP-42 emission factors

**Volatile Organic Compounds (VOC) BACT – Emergency Generator and Emergency Fire Pump**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of VOC emissions from operation of the natural gas fired pre-heaters and turbine gas conditioning heaters at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent tot the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

(a) **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
Limited hours of operation, compliance with NSPS IIII and good combustion/operating practices has been proposed as BACT for VOC from the emergency equipment associated with the IGCC plant:

(b) **New Source Performance Standards**
NSPS Subpart IIII applies to the emergency generator and fire pump. The proposed BACT for control of VOC from emergency generator and fire pump is equivalent to the emission limitation required by NSPS Subpart IIII.

*Step 5: Select BACT*

Pursuant to 320 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for VOC for the emergency equipment associated with the proposed IGCC plant:

(1) Compliance with NSPS IIII; and

(2) Good combustion/operating practices.

**Compliance Determination and Monitoring**

(1) Certification/plant documentation on meeting NSPS Subpart IIII emission limitations

(2) Recordkeeping of fuel usage

**Volatile Organic Compounds (VOC) BACT – Flare Pilot and Gasification Startup**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of VOC emissions from operation of the fuel combustion devices at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent tot the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

(a) **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The following has been proposed as BACT for VOC from the flare pilot and gasification startup associated with the IGCC plant:

(1) The gasification flare shall be maintained in good working order and shall operate per manufacturer's specifications.

(2) The VOC emissions from the gasification flare shall not exceed 0.005 lbs/MMBtu.

(3) Combustion of only natural gas in gasification flare pilot burner.

(4) The VOC emissions from the gasification flare shall not exceed one ton per year during startup operations.

(b) **Comparison with Other BACT Limitations**
Review of Information on the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies reveals that limited information is available on VOC emissions from a flare that supports a gasification process. Review of the Taylorville IGCC permit indicates that BACT for the gasification flare is the combustion of only natural gas in the flare pilot, operation of the flare pilot at all times, and good combustion practices.

(c) **New Source Performance Standards**
There are no NSPS requirements for VOC emissions from gasification flare.

*Step 5: Select BACT*

Pursuant to 320 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for VOC for the flare pilot and gasification startup associated with the proposed IGCC plant:

(1) The gasification flare shall be maintained in good working order and shall operate per manufacturer's specifications.

(2) The VOC emissions from the gasification flare shall not exceed 0.005 lbs/MMBtu.

(3) Combustion of only natural gas in gasification flare pilot burner.

(4) The VOC emissions from the gasification flare shall not exceed one ton per year during startup operations.

**Compliance Determination and Monitoring**

(1) Operate with a flame present at all times when emissions are vented to the flare;

(2) Test volume flow rate to flare during startup event and confirm/certify heating value of volume flow rate.

(3) Within 10 days of initial startup of any unit in the gasification block, confirm flare is in compliance with 40 CFR 60.18. Permittee must maintain appropriate documentation to demonstrate that identified process operation gas streams are connected to the flare header.

(4) Record of amount of natural gas combusted (MMCF) during each month, continuous presence of flare pilot flame and no visual emissions.

(5) Continuous monitoring of gas flow rate to flame.

(6) Determine visual emissions by Reference Method 22.

(7) Record hours of startup events. Emission estimates based hours of startup and pound per event emission factors.

**Volatile Organic Compounds (VOC) BACT – Thermal Oxidizer Burner and Gasification Operation**

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective method for control of VOC emissions from operation of the thermal oxidizer at an IGCC plant is the use of fuel specifications that employ clean burning fuels, implementation of good combustion practices and use of combustion controls inherent tot the design of the individual combustion devices.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Table 21 lists the proposed VOC BACT determination along with the existing VOC determinations for small natural gas fired boilers/heaters.

(a) **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN
The following has been proposed as BACT for VOC from the thermal oxidizer burner associated with the IGCC plant:

(1) The thermal oxidizer shall be maintained in good working order and shall operate per manufacturer's specifications.

(2) The VOC emissions from the gasification thermal oxidizer shall not exceed 0.005 lbs/MMBtu.

(3) The VOC emissions from the thermal oxidizer burner shall not exceed one ton per year during startup operations.

(b) **Comparison with other BACT limitations**
The VOC BACT limitations being proposed for the natural thermal oxidizer burner is equivalent to limitations established for small heaters/boilers at other facilities.

(c) **New Source Performance Standards**
There are no NSPS requirements for VOC emissions from the thermal oxidizer burner.

*Step 5: Select BACT*

Pursuant to 320 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for VOC for the thermal oxidizer burner associated with the proposed IGCC plant:

(1) The thermal oxidizer shall be maintained in good working order and shall operate per manufacturer's specifications.

(2) The VOC emissions from the gasification thermal oxidizer burner shall not exceed 0.005 lbs/MMBtu.

(3) Combustion of only natural gas in gasification thermal oxidizer burner.

(4) The VOC emissions from the thermal oxidizer burner shall not exceed one ton per year during startup operations.

**Compliance Determination and Monitoring**

(1) Operate at all times when an emission point vented to thermal oxidizer is in operation

(2) Permittee must maintain appropriate documentation to demonstrate that identified process operation gas streams are ducted to thermal oxidizer. Combustion temperature and residence time must be established and documented within 10 days of initial startup of the Sulfur Recovery Unit (SRU).

(3) Record amount of natural gas combusted (MMCF) during each month, date/time thermal oxidizer is not in operation

(4) Maintain daily records of visible emission notations of stack exhaust shall be performed once per day during normal daylight operations

(5) Maintain continuous temperature records (3-hr average)

**Requirement for CO, PM and VOC BACT – IGCC Startups and Shutdowns**

The following new emission units associated with the proposed IGCC plant at the Edwardsport Station have the potential to emit Carbon Monoxide, Particulate Matter (including $PM_{10}$ and $PM_{2.5}$) and Volatile Organic Compounds (VOC) during startup and shutdown events therefore, Best Available Control Technology analyses for CO, PM and VOC were performed for these events:

(1) Two (2) syngas/natural gas and combined syngas/natural gas-fired combustion turbines, identified as CTHRSG 1 and CTHRSG 2.

(2) One (1) 300 MMBtu/hr natural gas-fired auxiliary boiler, identified as AUXBLR.

(3) Two (2) natural gas-fired gasification pre-heater units, identified as GPREHEAT1 and GPREHEAT2.

(4) One (1) flare with a 2.6 MMBtu/hr natural gas fired pilot and sweep /purge gas, identified as FLR.

(5) One (1) 3.85 MMBtu/hr natural gas-fired thermal oxidizer, identified as THRMOX.

*Step 1: Identify Potential Control Technologies*

During the gasification startup process several supporting operations including the gas cooling system acid gas removal system and sulfur recovery unit are designed to vent exhaust gas streams to the flare or thermal oxidizer. Typically the sulfur recovery unit exhaust gas stream will be directed to the thermal oxidizer and the gas cooling and acid gas removal systems exhaust gas streams will go to the flare. The Auxiliary boiler is used to provide steam as needed to support startup activities, while the gas-fired gasification pre-heaters are used to heat the gasifiers to a specific threshold temperature to initiate the gasification process. The above exhaust gas stream configuration also occurs during the shutdown process of the gasification and power blocks.

Because of the uniqueness and complexity of the gasification and power blocks startups and shutdown events, the potential control technologies are some what limited. Duke Energy has concluded that the thermal oxidizer is the best technology for controlling exhaust gas streams from the sulfur recovery unit and that no other technologies exist that will meet the technical specification required. This is also true for the gas cooling and acid gas removal system. Because of the rate and temperature of exhaust gas flow and intermittent nature of these operations, as well as inadequate dispersion of ground level emissions that would result from a ground flare or enclosed flare, the only viable technology is an elevated open, natural gas-assisted flare. No other technologies exist that would meet the technical specifications of the operations exhaust gas streams.

As discussed in the previous section, there are no control technologies that are technically feasible for controlling CO, PM and VOC emissions from the combustion turbines. This conclusion is also valid for the combustion turbines during startup and shutdowns events. Any problems encountered with the combustion turbines during the startup event will allow for the exhaust gas stream (primarily uncombusted syngas) to be sent to the flare or thermal oxidizer.

There are no available control technologies to control emissions of CO, PM and VOC from the natural gas fired auxiliary boiler (which are at minor levels in any event).

*Step 2: Eliminate Technically Infeasible Options*

As presented in Step 1 the only viable control options to control emissions during startup and shutdown events are being proposed by use for the IGCC plant operations during these events

*Step 3: Rank the Remaining Control Technologies by Control Effectiveness.*

The most effective methods for control of CO, PM and VOC emissions from the IGCC operations during startup and shutdown events are those proposed by Duke Energy.

*Step 4: Evaluate the Most Effective Controls and Document the Results*

Review of the BACT/LAER Clearinghouse and recently issued permits for IGCC plants does not contain any specific BACT information or determinations for startup and shutdown events from this type of plant. The recently issued permit for the Taylorville IGCC plant does contain plant-wide ton/year limits for startup and shutdown events. No specific information was provided on whether or not these emission limits are BACT limits. It should be noted that Duke Energy is proposing BACT limits that are more stringent than the emission limits permitted for the Taylorville plant. Because of the lack of available information on BACT for startup and shutdown events from IGCC facilities, no technical summary tables are provided.

(a) **Proposal:** Duke Energy Indiana – Edwardsport Generating Station – Edwardsport, IN

The following has been proposed as BACT for CO, PM and VOC from each individual device associated with the IGCC plant during startup and shutdown events associated with the IGCC plant:

(1) Emissions from startups and shutdowns of the gasification block shall not exceed the following tons per year:

**Table 22: Startup & Shutdown Emissions Gasification Block**

| **Equipment** | **CO** | **PM*** | **VOC** |
|---|---|---|---|
| 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 |

* 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) Emissions from Startup and Shutdown of the power block shall not exceed the following tons per year:

| Table 23: Startup & Shutdown Emissions Power Block | | | |
|---|---|---|---|
| **Equipment** | **CO** | **PM*** | **VOC** |
| Aux Boiler | 46.0 | 4.2 | 3.0 |
| Combustion Turbines | 250.8 | 14.3 | 48.5 |
| **Total** | 296.8 | 18.5 | 51.5 |

* 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) **Comparison with other BACT Limitations**
The CO, PM and VOC BACT limitations being proposed for startup and shutdown events is more stringent than that proposed at other recently permitted IGCC Plants

(c) **New Source Performance Standards**
There are no NSPS requirements that apply to the IGCC operations during startup and shutdown events.

*Step 5: Select BACT*

Pursuant to 320 IAC 2-2-3 (PSD), the permittee shall comply with the following requirements for BACT for CO, PM and VOC for the IGCC plant during startup and shutdown events:

(1) Emissions from startups and shutdowns of the gasification block shall not exceed the following tons per year:

| Table 24: Startup & Shutdown Emissions Gasification Block | | | |
|---|---|---|---|
| **Equipment** | **CO** | **PM*** | **VOC** |
| 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 |

* 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) Emissions from Startup and Shutdown of the power block shall not exceed the following tons per year:

| Table 25: Startup & Shutdown Emissions Power Block | | | |
|---|---|---|---|
| **Equipment** | **CO** | **PM*** | **VOC** |
| Aux Boiler | 46.0 | 4.2 | 3.0 |
| Combustion Turbines | 250.8 | 14.3 | 48.5 |
| **Total** | 296.8 | 18.5 | 51.5 |

* 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 and Monitoring**

(1) **Thermal Oxidizer Operation**
Thermal oxidizer shall be in operation at all times when the sulfur recovery unit / tail gas unit is in operation.

(2) **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.

(3) **Gasification Block** – Startups and Shutdowns
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.

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

Appropriate Startup and Shutdown Emission Factor for each piece of emitting equipment from tables below shall be multiplied by the number of startup and shutdown events per month X 1 /2000

**Table 26: Startup & Shutdown Emission Factors**
**Gasification Thermal Oxidizer – Syngas**

| **Equipment** | **Total Time*** *(Hours)* | **CO** *(lbs)* | **PM** *(lbs)* | **VOC** *(lbs)* |
|---|---|---|---|---|
| **Startup Events** | | | | |
| Thermal Oxidizer | < 32 | 5.28 | 0.48 | 0.352 |
| Thermal Oxidizer | ≥ 32 to ≤ 62 | 155.0 | 13.99 | 10.13 |
| Thermal Oxidizer | ≥ 63 | 161.9 | 14.58 | 10.5 |
| 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 Events** | | | | |
| Thermal Oxidizer | ≤ 5 | 5.9 | 0.53 | 0.37 |
| Thermal Oxidizer | > 5 | 13.4 | 1.2 | 0.8 |

*Total Time for a specific Startup or Shutdown Event

(4) **Power Block** – Startups and Shutdowns
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.

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

Appropriate Startup and Shutdown Emission Factor for each piece of emitting equipment from tables below shall be multiplied by the number of startup and shutdown events per month X 1 /2000

**Table 27: Startup & Shutdown Emission Factors**
**Auxiliary Boiler – Natural Gas**

| **Equipment** | **Total Time*** *(Hours)* | **CO** *(lbs)* | **PM** *(lbs)* | **VOC** *(lbs)* |
|---|---|---|---|---|
| **Startup Events** | | | | |
| Gasification Auxiliary Boiler | < 32 | 790.6 | 71.5 | 51.8 |
| Gasification Auxiliary Boiler | ≥ 32 to ≤ 62 | 1210.6 | 109.5 | 79.3 |
| Gasification Auxiliary Boiler | ≥ 63 | 1210.6 | 109.5 | 79.3 |
| **Shutdown Events** | | | | |
| Gasification Auxiliary Boiler | ≤ 5 | NA | NA | NA |
| Gasification Auxiliary Boiler | > 5 | NA | NA | NA |

*Total Time for a specific Startup or Shutdown Event

**Table 28: Startup & Shutdown Emission Factors**
**Combined Cycle Combustion Turbines – Syngas**

| **Equipment** | **Total Time*** *(Hours)* | **CO** *(lbs)* | **PM** *(lbs)* | **VOC** *(lbs)* |
|---|---|---|---|---|
| **Startup Events** | | | | |
| Combustion Turbines | < 32 | 0.0 | 0.0 | 0.0 |
| Combustion Turbines | ≥ 32 to ≤ 62 | 5976.2 | 310.7 | 1178.0 |
| Combustion Turbines | ≥ 63 | 6433.5 | 367.3 | 1247.5 |
| **Shutdown Events** | | | | |
| Combustion Turbines | ≤ 5 | 164.6 | 10.8 | 29.0 |
| Combustion Turbines | > 5 | 0.0 | 0.0 | 0.0 |

*Total Time for a specific Startup or Shutdown Event

(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.

**IDEM Contact**

Questions regarding this proposed permit can be directed to:

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# Indiana Department of Environmental Management
## Office of Air Quality

Appendix C – Air Quality Analysis
Technical Support Document (TSD)
Prevention of Significant Deterioration (PSD)
Significant Source Modification (SSM) of a Part 70 Source
Significant Permit Modification (SPM) of Part 70 Operating Permit

## Source Background and Description

| | |
|---|---|
| Source Name: | Duke Energy Indiana – Edwardsport Generating Station |
| Source Location: | 15424 East State Road 358, Edwardsport, Indiana 47258 |
| County: | Knox |
| SIC Code: | 4911 |
| Operation Permit No.: | T 083-7243-00003 |
| Operation Permit Issuance Date: | August 10, 2004 |
| Significant Source Modification No.: | SSM 083-23529-00003 |
| Significant Permit Modification No.: | SPM 083-23531-00003 |
| Permit Reviewer: | Kimberly Cottrell |

## 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. This technical support document provides the air quality analysis review of the permit application.

## Analysis Summary

Based on the net emissions changes after controls, a PSD air quality analysis was triggered for CO and $PM_{10}$. For VOCs, no analysis is required. 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 NOx. 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, Gibson and Vanderburgh Counties.) An additional impact analysis was conducted and showed no significant impact. A Hazardous Air Pollutant (HAP) analysis was performed. Based on the HAPs modeling results, the source will not pose a health concern.

## 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 in significant amounts 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, $PM_{10}$, NOx, $SO_2$, 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 will require an air quality analysis. Since the emissions for the project for all pollutants will be above the significant emission rate, they will be 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 |
| $NO_x$ | 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 stimulate 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)**

**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 would affect 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 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 1988 through 1992 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 AERMOD, Version 07026. OAQ used the same model version 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. The receptor grid contains 4838 individual receptors.

- 100 meter spacing along the facility's property boundary,
- 100 meter spacing from 0 to 1,000 meters from the facility,
- 250 meters spacing from 1,000 to 3,000 meters from the facility,
- 500 meters spacing from 3,000 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 K of the air quality technical support document provided by Malcolm Pirnie.

## 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 would exceed these levels, further air quality analysis is required. Refined modeling for CO, $PM_{10}$, $SO_2$, and NOx 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 |
|---|---|---|---|---|
| NOx | Annual* | 22.4 | 1 | Yes |
| $PM_{10}$ | Annual* | 3.88 | 1 | Yes |
| $PM_{10}$ | 24 hour* | 23.5 | 5 | Yes |
| $SO_2$ | 3 hour* | 95.2 | 25 | Yes |
| $SO_2$ | 24 hour* | 29.9 | 5 | Yes |
| $SO_2$ | Annual* | 2.98 | 1 | Yes |
| CO | 1 hour* | 8312 | 2000 | Yes |
| CO | 8 hour* | 3850 | 500 | Yes |

*First highest values per EPA NSR manual October 1990. Impacts are from the Duke Energy only.

## Pre-construction Monitoring Analysis

### 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

A comparison of the modeling results was 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 |
|---|---|---|---|---|
| NOx | Annual* | 22.4 | 14 | Yes |
| $PM_{10}$ | 24 hour* | 23.5 | 10 | Yes |
| $SO_2$ | 24 hour* | 29.9 | 13 | Yes |
| CO | 8 hour* | 2505 | 575 | Yes |

***First highest values per EPA NSR manual October 1990. Maximum modeled impacts are from Duke Energy only.

CO, NOx, $PM_{10}$ 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 closest monitoring stations from Duke Energy. The closest $SO_2$ station is located in Daviess County. The closest $PM_{10}$ and NOx monitoring station is located in Dubois and Gibson Counties. The closest CO monitor is 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) |
|---|---|---|---|

| | | | |
|---|---|---|---|
| NOx | 18-051-0010 | Annual | 17.1 |
| $PM_{10}$ | 18-037-2001 | Annual | 26 |
| $PM_{10}$ | 18-037-2001 | 24 hour | 46.3 |
| CO | 18-163-0015 | 1 hour | 6297.5 |
| CO | 18-163-0015 | 8 hour | 3893 |
| $SO_2$ | 18-027-0002 | 3 hour | 210.4 |
| $SO_2$ | 18-027-0002 | 24 hour | 86.5 |
| $SO_2$ | 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. The NAAQS inventories are generated from I-STEPS (State Emission Processing System) 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.

NAAQs modeling for the appropriate time-averaging periods for NOx, $PM_{10}$ 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[3]**
**NAAQS Analysis**

| **Pollutant** | **Year** | **Time-Averaging Period** | **Maximum Concentration ug/m3** | **Background Concentration ug/m3** | **Total ug/m3** | **NAAQS Limit ug/m3** | NAAQS Violation |
|---|---|---|---|---|---|---|---|
| NOx | 1991 | Annual[1] | 19.9 | 17.1 | 37.0 | 100 | NO |
| $PM_{10}$ | 1992 | Annual[1] | 0.9 | 26 | 26.9 | 50 | NO |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| $PM_{10}$ | 1988 | 24 hour | 23.7 | 46.3 | 70.0 | 150 | NO |
| CO | 1988 | 1 hour | 8312 | 6297.5 | 14609.5 | 40000 | NO |
| CO | 1992 | 8 hour | 3850 | 3893 | 7743 | 10000 | NO |
| $SO_2$ | 1991 | 3 Hour[2] | 70.9 | 210.4 | 281.3 | 1300 | NO |
| $SO_2$ | 1988 | 24 hour[2] | 41.0 | 86.5 | 127.5 | 365 | NO |
| $SO_2$ | 1991 | Annual[1] | -1.9[4] | 19.4 | 17.5 | 80 | NO |

[1] First highest values per EPA NSR manual October 1990.
[2] High 2nd high values per EPA NSR manual October 1990.
[3] 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 3 maximum concentrations are from Duke Energy only.
[4] Negative impact due to shutdown of the old boilers.

**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 NOx, $SO_2$, 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 NOx, $SO_2$, and $PM_{10}$ modeled above significant impact levels, a PSD increment analysis for Duke Energy and surrounding sources was required. Results of the increment modeling are summarized in Table 6 below.

**TABLE 6[3]**
**Increment Analysis**

| Pollutant | **Year** | **Time-Averaging Period** | **Maximum Concentration ug/m3** | **PSD Increment Ug/m3** | **Percent Impact on the PSD Increment** | Increment Violation |
|---|---|---|---|---|---|---|
| NOx | 1991 | Annual[1] | 19.9 | 25 | 79.6 | NO |
| $PM_{10}$ | 1992 | Annual[1] | 0.9 | 17 | 5.3 | NO |
| $PM_{10}$ | 1988 | 24 hour[2] | 23.7 | 30 | 79.0 | NO |
| $SO_2$ | 1991 | Annual[1] | -1.9[4] | 20 | N/A | NO |
| $SO_2$ | 1991 | 3 hour[2] | 70.9 | 512 | 13.8 | NO |
| $SO_2$ | 1988 | 24 hour[2] | 41 | 91 | 45 | NO |

**1** First highest value per EPA NSR manual October 1990.
**2** Highest second high per EPA NSR manual October 1990.
[3] 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 3 maximum concentrations are from Duke Energy only.
[4] Negative impact due to shutdown of the old boilers.

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 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.

**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

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 are estimated to be 13 tons per year.

For Duke Energy, a full HAP analysis was completed 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, the cancer 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 Duke Energy’s Hazard Index (HI).

This HAP screening analysis uses health protective assumptions that overestimate the actual risk associated with emissions from Duke Energy. 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; 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** | |
| 2-Methylnaphthalene | 3.64E-05 | 6.62E-04 | | | 70.00 | 0.000 |
| 3-Methylcholanthrene | 1.41E-06 | 4.97E-07 | 6.3E-03 | 3.13E-09 | | |
| 7,12-Dimethylbenz[a]anthracene | 1.25E-06 | 4.42E-07 | 7.1E-02 | 3.14E-08 | | |
| Acenaphthene | 1.41E-06 | 4.97E-07 | | | 210.00 | 0.000 |
| Acenaphthylene | 1.41E-06 | 4.97E-07 | | | 35.00 | 0.000 |
| Acetaldehyde | 7.4E-01 | 6.20E-03 | 2.2E-06 | 1.36E-08 | 9.00 | 0.001 |
| Acrolein | 1.18E-01 | 2.16E-04 | | | 0.02 | 0.011 |
| Anthracene | 1.88E-06 | 6.62E-02 | | | 1050.00 | 0.000 |
| Arsenic compounds | 1.45E-02 | 2.06E-05 | 4.3E-03 | 8.86E-08 | 0.03 | 0.001 |
| Benzene | 2.26E-01 | 1.17E-02 | 7.8E-06 | 9.13E-08 | 30.00 | 0.000 |
| Benzo[a]anthracene | 1.41E-06 | 4.97E-07 | 1.1E-04 | 5.47E-11 | | |
| Benzo[a]pyrene | 9.38E-07 | 3.31E-07 | 1.1E-03 | 3.64E-10 | | |
| Benzo[b]fluoranthene | 1.41E-06 | 4.97E-07 | 1.1E-04 | 5.47E-11 | | |
| Benzo[g,h,i]perylene | 9.38E-07 | 3.31E-07 | 8.9E-03 | 2.95E-09 | | |
| Benzo[k]fluoranthene | 1.41E-06 | 4.97E-07 | 1.1E-04 | 5.47E-11 | | |
| Beryllium compounds | 1.62E-03 | 2.30E-06 | 2.4E-03 | 5.52E-09 | 0.02 | 0.000 |
| Cadmium compounds | 2.02E-02 | 2.87E-05 | 1.8E-03 | 5.17E-08 | 0.02 | 0.001 |
| Chromium (VI) compounds | 9.34E-03 | 1.33E-05 | 1.2E-02 | 1.60E-07 | 0.10 | 0.000 |
| Chrysene | 1.41E-06 | 4.97E-07 | 8.9E-04 | 4.42E-10 | | |
| Dibenz[a,h]anthracene | 9.38E-07 | 3.31E-07 | 1.2E-03 | 3.97E-10 | | |
| Dichlorobenzene | 9.38E-04 | 3.31E-04 | 6.9E-06 | 2.27E-09 | 200.00 | 0.000 |
| Ethylbenzene | 5.9E-01 | 8.40E-04 | | | 1000.00 | 0.000 |
| Fluoranthene | 2.35E-06 | 8.28E-04 | | | 140.00 | 0.000 |
| Fluorene | 2.19E-06 | 7.73E-07 | | | 140.00 | 0.000 |
| Formaldehyde | 5.97 | 3.72E-02 | 1.3E-05 | 4.84E-07 | 9.80 | 0.004 |
| Indeno[1,2,3-cd]pyrene | 1.41E-06 | 4.97E-07 | 1.1E-04 | 5.47E-11 | | |
| Lead compounds | 3.72E-02 | 5.28E-05 | 1.2E-05 | | 0.15 | 0.000 |
| Manganese compounds | 9.87E-03 | 1.40E-05 | | | 0.05 | 0.000 |
| Mercury compounds | 3.60E-03 | 5.11E-06 | | | 0.09 | 0.000 |
| Naphthalene | 2.48E-02 | 1.56E-03 | 3.4E-05 | 5.30E-08 | 3.00 | 0.001 |
| n-Hexane | 1.41 | 4.97E-01 | | | 200.00 | 0.002 |
| Nickel compounds | 1.05E-02 | 1.49E-05 | 2.4E-04 | 3.58E-09 | 0.20 | 0.000 |
| Phenanthrene | 1.33E-05 | 4.69E-06 | | | 10.50 | 0.000 |
| Propylene | 4.18E-02 | 1.84E-01 | | | 3000.00 | |
| Pyrene | 3.91E-06 | 1.38E-06 | | | 105.00 | 0.000 |
| Silica | 1.77E-01 | 2.52E-04 | | | 3.00 | 0.000 |
| Selenium compounds | 1.43E-02 | 2.03E-05 | | | 20.00 | 0.000 |
| Toluene | 2.41 | 8.76E-03 | | | 400.00 | 0.000 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Xylenes | 1.18 | 4.66E-03 | | | 100.00 | 0.000 |
| Zinc Compounds | 1.18E-02 | 1.67E-05 | | | 0.90 | 0.000 |
| Total HAPS | 13.02 | | **Total Cancer Risk** | **9.9163E-07** | **Hazard Index** | **0.0220** |

* 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 0.99 additional cancer cases in one million people. This means if an individual was exposed to these HAPs continuously for 70 years, the risk of getting cancer from this exposure would be 0.99 in one million. 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

Malcolm Pirnie prepared the modeling portion of the PSD application. Knox County is designated as attainment for all criteria pollutants. VOCs, $PM_{10}$, NOx, $SO_2$, 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 NOx impacts were predicted to be greater than the significant impact levels. Duke Energy did trigger the preconstruction monitoring threshold level for CO, $PM_{10}$, NOx 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, $PM_{10}$, NOx, 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
# Office of Air Quality

## Appendix D – Proposed Changes to Part 70 Operating Permit
## Technical Support Document (TSD)
## Significant Source Modification (SSM) of a Part 70 Source
## Significant Permit Modification (SPM) of Part 70 Operating Permit

### Source Background and Description

| | |
|---|---|
| Source Name: | Duke Energy Indiana – Edwardsport Generating Station |
| Source Location: | 15424 East State Road 358, Edwardsport, Indiana 47258 |
| County: | Knox |
| SIC Code: | 4911 |
| Operation Permit No.: | T 083-7243-00003 |
| Operation Permit Issuance Date: | August 10, 2004 |
| Significant Source Modification No.: | SSM 083-23529-00003 |
| Significant Permit Modification No.: | SPM 083-23531-00003 |
| Permit Reviewer: | Kimberly Cottrell |

### Proposed Expansion

On August 18, 2006, the Office of Air Quality (OAQ) received an application from Duke Energy Indiana to install a integrated gasification and combined cycle (IGCC) electric generating plant at the Edwardsport Generating Station, located at State Road 67, Edwardsport, Indiana, in Knox County. Pursuant to 326 IAC 2-2-3(3) (PSD Rule: Control Technology Review Requirements), a major modification shall apply Best Available Control Technology (BACT) for each regulated NSR pollutant for which the modification would result in a significant net emissions increase at the source. The Edwardsport Generating Station 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", which is a listed source category pursuant to 326 IAC 2-2-1(gg)(1). The Edwardsport IGCC project is subject to 326 IAC 2-2-3(2) because, pursuant to 326 IAC 2-2-1(xx), the net emissions increase will equal or exceed the significant increase thresholds of one hundred (100) tons per year of carbon monoxide (CO), forty (40) tons per year of volatile organic compounds (VOC), twenty-five (25) tons per year of particulate matter (PM), and fifteen (15) tons per year of $PM_{10}$.

### General Changes

The changes listed in each of the sections below have been made to Part 70 Operating Permit No. T083-7243-00003.

**Change No. 1: Emission Unit Descriptions**

The emission unit descriptions were modified in Sections A, D, E, and F to include reference to the new integrated gasification and combined cycle (IGCC) electric generating plant and to note that the existing equipment is to be retired. The new equipment list is as follows:

**Change No. 2: IDEM Mailing Address Changes**

The IDEM address has been updated throughout the permit as follows to include the mail code specific to each section of the Office of Air Quality:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue~~, P.O. Box 6015~~
**MC 61-50, IGCN 1003**
Indianapolis, Indiana ~~46206-6015~~ **46204-2251**

Indiana Department of Environmental Management
Asbestos Section, Office of Air Quality
100 North Senate Avenue~~, P.O. Box 6015~~
**MC 61-52, IGCN 1003**
Indianapolis, Indiana ~~46206-6015~~ **46204-2251**

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue~~, P.O. Box 6015~~
**MC 61-53, IGCN 1003**
Indianapolis, Indiana ~~46206-6015~~ **46204-2251**

Indiana Department of Environmental Management
Air Compliance Section, Office of Air Quality
100 North Senate Avenue~~, P.O. Box 6015~~
**MC 61-53, IGCN 1003**
Indianapolis, Indiana ~~46206-6015~~ **46204-2251**

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue~~, P.O. Box 6015~~
**MC 61-53, IGCN 1003**
Indianapolis, Indiana ~~46206-6015~~ **46204-2251**

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue~~, P.O. Box 6015~~
**MC 61-53, IGCN 1003**
Indianapolis, Indiana ~~46206-6015~~ **46204-2251**

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue~~, P.O. Box 6015~~
**MC 61-53, IGCN 1003**
Indianapolis, Indiana ~~46206-6015~~ **46204-2251**

**Change No. 3: IDEM, OAQ Compliance Branch Phone and Fax Number changes**

All references to the IDEM, OAQ, Compliance Section telephone and facsimile numbers have been revised as follows:

Telephone Number: ~~317-233-5674~~ **317-233-0178**

Facsimile Number: ~~317-233-5967~~ **317-233-6865**

## Changes to Section A

The following changes have been made to Section A of the Part 70 Operating Permit:

**Change No. 4: TSD – Attainment Status**

On August 7, 2006, a temporary emergency rule took effect redesignating Delaware, Greene, Jackson, Vanderburgh, Vigo and Warrick Counties to attainment for the eight-hour ozone standard, redesignating Lake County to attainment for the sulfur dioxide standard, and **revoking the one-hour ozone standard in Indiana**. The Indiana Air Pollution Control Board has approved a permanent rule revision to incorporate these changes into 326 IAC 1-4-1. The permanent revision to 326 IAC 1-4-1 will take effect prior to the expiration of the emergency rule.

**Change No. 5: Responsible Official (RO) / Authorized Individual Section A changes**

To minimize future amendments to the issued Part 70 Permits, the OAQ decided to delete the name and/or title of the Responsible Official (RO) in Section A.1, General Information, of the permit. However, OAQ will still be evaluating if a change in RO meets the criteria specified in 326 IAC 2-7-1(34). The revised permit condition is as follows:

**Change No. 6: New Equipment**

Condition A.2 is revised to include the emission units descriptions for each piece of equipment associated with the IGCC Plant.

**Change No. 7: Retiring Equipment**

Language was added to Condition A.2 to specify that the existing emission units are to be retired prior to operation of the IGCC Plant.

## Changes to Section B

The following changes have been made to Section B of the Part 70 Operating Permit:

**Change No. 8: Supersession Revisions**

To clarify the permit term and the term of the conditions, original Conditions B.2 – Permit Term, B.13 – Prior Permits Superseded, and B.16 – Permit Renewal have been modified. Additionally, a new Section B condition, B.3 – Term of Conditions has been added.

**Change No. 9: Termination of Right to Operate**

IDEM has rearranged the permit conditions such that original Condition B.4 – Termination of Right to Operate is now Condition B.14.

**Change No. 10: Annual Compliance Certification**

Instructions for the original Condition B.9 – Annual Compliance Certification (ACC) have been revised. The emission statement reporting requirements changed. The submission date for the ACC will continue to depend on which county the source is located.

**Change No. 11: PMP and Emergency Conditions**

IDEM has determined that the Permittee is not required to keep records of all preventive maintenance. However, where the Permittee seeks to demonstrate that an emergency has occurred, the Permittee must provide, upon request records of preventive maintenance in order to establish that the lack of proper maintenance did not cause or contribute to the deviation. Therefore, IDEM has deleted paragraph (b) of original Condition B.10 – Preventive Maintenance Plan and has amended original Condition B.11 – Emergency Provisions.

**Change No. 12: Nonroad engines – Permit Amendment or Modification**

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

**Change No. 13: Operational Flexibility**

For clarification purposes, Condition B.20 – Operational Flexibility has been revised.

**Change No. 14: Credible Evidence**

Indiana has incorporated the credible evidence provision in 326 IAC 1-1-6. This rule became effective on March 16, 2005; therefore, revisions to the condition reflecting this rule will be incorporated into Condition B.25 – Credible Evidence.

## Changes to Section C

The following changes have been made to Section C of the Part 70 Operating Permit:

**Change No. 15: 326 IAC 6-3-2 and C.1 Condition**

Revisions to 326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes) became effective on June 12, 2002 and were approved into the State Implementation Plan on September 23, 2005. These rules replace the previous version of 326 IAC 6-3 that had been part of the SIP; therefore, the requirements of the previous version of 326 IAC 6-3-2 are no longer applicable to this source. Original Condition C.1 – Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour has been revised to remove (a) which contained these requirements, and original Condition D.1.4 – Particulate Matter (PM) [40 CFR 52 Subpart P] which contained these requirements has been removed. Original Condition D.1.9 – Record Keeping Requirements will no longer refer to Condition D.1.4, and since the requirements of the 326 IAC 6-3-2(d) that were effective June 12, 2002 are now federally enforceable, the last statements from original Conditions C.1 and D.1.9 have been removed.

**Change No. 16: Incineration**

The last sentence of original Condition C.4 – Incineration, was deleted because the provisions of 326 IAC 9-1-2 are federally enforceable and are included in Indiana's State Implementation Plan (SIP).

**Change No. 17: Maintenance of Continuous Emission Monitoring Equipment – COM Downtime**

IDEM has determined that no additional monitoring will be required during COM downtime, until the COM has been down for twenty-four (24) hours. This allows the Permittee to focus on the task of repairing the COM during the first twenty-four (24) hour period. After twenty-four (24) hours of COM downtime, the Permittee will be required to conduct Method 9 readings for thirty (30) minutes. Once Method 9 readings are required to be performed, the readings should be performed twice per day at least 4 or 6 hours apart, rather than once every four (4) hours, until a COMS is back in service.

**Change No. 18: Instrument Specifications**

IDEM realizes that the specifications of original Condition C.14 – Pressure Gauge and Other Instrument Specifications, can only be practically applied to analog units, and has therefore clarified the condition to state that the condition only applies to analog units. Upon further review, IDEM has also determined that the accuracy of the instruments is not nearly as important as whether the instrument has a range that is appropriate for the normal expected reading of the parameter. Therefore, the language in original Condition C.14 has been revised.

**Change No. 19: Response to Excursions or Exceedances**

IDEM has reconsidered the requirement to develop and follow a Compliance Response Plan (original Condition C.17). The Permittee will still be required to take reasonable response steps when a compliance monitoring parameter is determined to be out of range or abnormal. Replacing the requirement to develop and follow a Compliance Response Plan with a requirement to take reasonable response steps will ensure that the control equipment is returned to proper operation as soon as practicable, while still allowing the Permittee the flexibility to respond to situations that were not anticipated. Therefore, original Condition C.17 for the "Compliance Response Plan" has been replaced by Condition C.17 for the "Response to Excursions or Exceedances". The Section D conditions that refers to this condition have been revised to reflect the new condition title (Refer to the changes in the section of Proposed Changes).

**Change No. 20: Actions Related to Noncompliance Demonstrated by a Stack Test**

Paragraph (b) of Condition C.18, Actions Related to Noncompliance Demonstrated by a Stack Test, is revised as follows to correct a typographical error:

~~one-hundred and twenty (120) days~~
**one hundred twenty (120) days**

**Change No. 21: Emission Statement**

Revisions were made to the Emission Statement condition (original Condition C.19) to incorporate the revisions to 326 IAC 2-6 that became effective March 27, 2004. The revised rule was published in the April 1, 2004 Indiana Register.

**Change No. 22: General Record Keeping Requirements and General Reporting Requirements**

Revisions to have been made to the Section C – General Recordkeeping and Section C – General Reporting Requirements (original Conditions C.20 and C.21) to reflect NSR (New Source Review) reform provisions at the major sources.

## Changes to Section D

The following changes have been made to Section D of the Part 70 Operating Permit:

**Change No. 23: Why the PMPs are required**

The Preventive Maintenance Plan (PMP) requirement must be included in every applicable Part 70 permit pursuant to 326 IAC 2-7-5 (13). This rule refers back to the Preventive Maintenance Plan (PMP) requirement found in 326 IAC 1-6-3. This Preventive Maintenance Plan (PMP) rule sets out the requirements for:

(a) Identification of the individuals responsible for inspecting, maintaining and repairing the emission control equipment. [326 IAC 1-6-3 (a)(1)]

(b) The description of the items or conditions in the facility that will be inspected and the inspection schedule for said items or conditions. [326 IAC 1-6-3(a)(2)]

(c) The identification and quantification of the replacement parts for the facility, which the Permittee will maintain in inventory for quick replacement. [326 IAC 1-6-3(a)(2)]

The structure of 326 IAC 1-6-3 applies to the owner or operator of any facility required to obtain a permit and the PMP requirement affects the entirety of the applicable facilities. Only 326 IAC 1-6-3(a)(1) is limited, in that it requires identification of the personnel in charge of only the emission control equipment, and not any other facility equipment. 326 IAC 1-6-3(b) provides that "...as deemed necessary by the commissioner, any person operating a facility shall comply with the requirements of subsection (a) of this section." In addition to preventive maintenance performed on the control devices, preventive maintenance should also be performed on the emission units themselves because lack of proper maintenance on the units can result in increased emissions. Many types of facilities require maintenance in order to prevent excess emissions.

**Change No. 24: Testing**

Testing Requirements are required to demonstrate compliance with the Emission Limits.

**Change No. 25: Compliance Monitoring**

Compliance Monitoring Requirements (Visible Emissions Notations, Parametric Monitoring, etc.) are required to demonstrate compliance with the Emission Limits. Visible Emissions Notations are required in order to comply with the fugitive dust emission limitation.

**Change No. 26: Visible Emissions Notations & Record Keeping Requirements - "when venting to the atmosphere"**

IDEM has decided that the phrase "when venting to the atmosphere" is only appropriate if the unit is capable of venting both indoors and outdoors, such as some woodworking facilities that vent indoors in the winter and outdoors in the summer.

**Change No. 27: Visible Emissions Notations & Record Keeping Requirements - "when venting to the atmosphere"**

The intent of Record Keeping Requirements for Visible Emission Notations and Parametric Monitoring is that the Permittee needs to make a record of some sort every day. An example for Visible Emission Notations would be "normal" or "abnormal". Additionally, if Visible Emission Notations were not done on a particular day, the Permittee needs to specify the reason why the observation was not done. An example of this record would be "the unit was not operating" or "the unit was venting indoors".

**Change No. 28: PMP Required Routine Control Device Inspections**

IDEM has determined that it is the Permittee's responsibility to include routine control device inspection requirements in the applicable preventive maintenance plan. Since the Permittee is in the best position to determine the appropriate frequency of control device inspections and the details regarding which components of the control device should be inspected, the conditions requiring control device inspections have been removed from the permit. In addition, the requirement to keep records of the inspections has been removed.

**Change No. 29: Frequency of Control Device Parametric Monitoring – Once per day Visible Emissions and Monitoring of Control Device**

IDEM has determined that once per day visible emission notations and once per day monitoring of the control device is generally sufficient to ensure proper operation of the emission units and control devices. Therefore, the monitoring frequency has been changed from once per shift to once per day in the revised permit.

**Change No. 30: Broken or Failed Bag Detection**

Paragraph (a) of the Section D – Broken or Failed Baghouse conditions has been deleted and replaced with a condition specific to single compartment baghouses which control emissions from continuously operating processes.

**Change No. 31: Batch Mode Processes And Baghouse/Scrubber/Cyclone/Filter Failure**

Paragraph (b) of the Section D – Broken or Failed Baghouse conditions has been revised for those processes that operate in batch mode. The condition required an emission unit to be shut down immediately in case of baghouse failure. However, IDEM is aware there can be safety issues with shutting down a process in the middle of a batch. IDEM also realizes that in some situations, shutting down an emissions unit mid-process can cause equipment damage. Therefore, since it is not always possible to shut down a process with material remaining in the equipment, IDEM has revised the condition to state that in the case of baghouse failure, the feed to the process must be shut off immediately, and the process shall be shut down as soon as practicable.

**Change No. 32: Multi-Compartment Baghouses Responses**

For multi-compartment baghouses, the permit will not specify what actions the Permittee needs to take in response to a broken bag. Therefore, a requirement has been added to the Section D – Particulate Control conditions requiring the Permittee to notify IDEM if a broken bag is detected and the control device will not be repaired for more than ten (10) days. This notification allows IDEM to take any appropriate actions if the emission unit will continue to operate for a long period of time while the control device is not operating in optimum condition.

**Change No. 33: Removing 40 CFR 52 as Authority for PSD/Emission Offset**

On March 3, 2003, U.S.EPA published a notice for “Conditional Approval of Implementation Plan: Indiana” in the Federal Register / Vol. 68, No. 41 at pages 9892 through 9895. This notice grants conditional approval to the PSD State Implementation Plan (SIP) under provisions of 40 CFR §51.166 and 40 CFR §52.770 while superseding the delegated PSD SIP authority under 40 CFR §52.793. The effective date for these provisions is April 2, 2003. Therefore, the PSD permits will be issued under the authority of 326 IAC 2-2 and will no longer be issued under the provision of 40 CFR 52.21 and 40 CFR 124.

**Change No. 34: New Equipment**

New operating conditions have been added as Sections D.7 through D.11 to specify the requirements that apply to the IGCC Plant.

**Change No. 35: Retiring Equipment**

Language was added to the Facility Descriptions for Sections D.1 through D.6 and Section E to specify that the existing emission units are to be retired prior to operation of the IGCC Plant.

## Changes to Section E

There are no other changes to Section E of the Part 70 Operating Permit:

## Section F

The following changes have been made regarding Section F of the Part 70 Operating Permit:

**Change No. 36: Nitrogen Oxides Budget Trading Program**

Section F was added to include the applicable requirements of the Nitrogen Oxides Budget Trading Program for this Part 70 Operating Permit.

## Section G

The following changes have been made regarding Section G of the Part 70 Operating Permit:

**Change No. 37: New Source Performance Standards**

Sections G.1 through G.6 were added to include the New Source Performance Standards (40 CFR 60, Subparts Da, Db, Y, OOO, HHHH, and IIII) that are applicable to the emission units and processes of this Part 70 Operating Permit.

## Changes to Reporting Forms

The following changes have been made to the reporting forms for this Part 70 Operating Permit:

**Change No. 38: Updated Forms**

IDEM has updated the existing forms to reflect changes to the IDEM address and other minor changes that are addressed more specifically above.

## Fugitive Dust Control Plan

The following changes have been made regarding the Fugitive Dust Control Plan for this Part 70 Operating Permit:

**Change No. 39: New Source Performance Standards**

The Fugitive Dust Control Plan required for this modification has been added as Attachment A to the Part 70 Operating Permit.

## IDEM Contact

Questions regarding this proposed permit can be directed to:

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Please refer to Significant Source Modification No.: 083-23529-00003 and Significant Permit Modification No.: 083-23531-00003 in all correspondence.